From:	Reiten, John R.
To:	Travnicek, Andrea J.; Bohrer, Mark F.; Haase, Reice; Tyler, Karen J.; Bialke, Joseph P.; Stegmiller, Joseph H.; Suelzle, Chris; Schulz, Cody J.; Garman, Cole; Ebach, Abby S.; Glatt, Dave D.; Schuh, John M.; Heringer, Joe A.
Cc:	Beehler, Jace; Svihovec, Nathan J.; Sagsveen, Matthew A.; Seby, Paul (Shld-DEN-Env); Nowatzki, Mike G.
Subject:	FINAL DECISION: North Dakota BLM RMP
Date:	Thursday, August 8, 2024 1:39:54 PM
Attachments:	NDRMP_PRMP_FEIS_Vol1_508.pdf Final ND RMP Comments.pdf

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Good afternoon,

This morning, the BLM issued its final decision on the resource management plan (RMP). I have attached the state's previous comments for your reference. As a reminder, we submitted comments on this RMP on May 22nd, 2023. The next step in the RMP process is a 30-day Governor's consistency review, which begins TOMORROW. During this period, if the Governor believes the RMP conflicts with state land management, he can pause the process.

We have 30 days to review the RMP and decide whether to recommend he protest their decision.

They have made a decision that we did not request, and there are several reasons why we might consider recommending protesting. Each of you has the specialized expertise to help make the best determinations.

I will schedule a kickoff call to discuss the RMP with Paul Seby, who wrote our last comments. He will explain the process in greater detail and highlight key points to consider during your review.

Thank you for your attention to this matter. Below is a section of text from the BLM email regarding the RMP.

I believe I have all the relevant agencies in this email, but please let me know if I am missing anyone.

- DWR
- DMR
- P&R
- DEQ
- NDIC
- AGo
- DTL
- NDDA

Thank you!

John

The Proposed RMP/Final Environmental Impact Statement (EIS) includes five alternatives for managing the planning area. These alternatives have been developed based on careful consideration of various factors, including ecological integrity, habitat preservation, development scenarios, and *resource conservation.*

To summarize the alternatives:

- Alternative A: Current 1988 RMP, with limited restrictions on energy development.

- Alternative B: Preferred alternative in the Draft RMP/EIS, emphasizing sustaining ecological integrity while allowing appropriate development scenarios. It includes Special Recreation Management Areas (SRMA), Backcountry Conservation Areas (BCA), and Areas of Critical Environmental Concern (ACEC).

- Alternative B.1: A sub-alternative to Alternative B, providing similar management opportunities and protections, but with limitations on federal coal leasing.
- Alternative C: Similar to Alternative B, but with more flexibility in the management of allowable uses.

- ***Alternative D: Proposed Plan in the Final EIS,*** *emphasizing recreation, cultural, and natural resource management, with limitations on leasing for oil, gas, and coal. It includes closures of low development potential areas and state-designated drinking water source protection areas.*

The Proposed RMP (Alternative D) incorporates management actions and allowable uses from Alternatives A, B, and C. Changes have been made in response to public comments, cooperating agency input, and extensive internal BLM reviews.

This release formally initiates the 30-day protest period and 60-day Governor's Office review. We'd like to invite you to review the Proposed RMP/Final EIS and supporting information on the ePlanning project website at https://eplanning.blm.gov/eplanning-ui/project/1505069/510.

Instructions for filing a protest can be found at https://www.blm.gov/programs/planning-and-nepa/public-participation/filing-a-plan-protest and at 43 CFR 1610.5. All protests must be submitted in writing through one of the following methods:

- *Website: https://eplanning.blm.gov/eplanning-ui/rpoject/1505069/510*
- *Mail: BLM Director, Attention: Protest Coordinator (HQ210), Denver Federal Center, Building 40 (Door W-4), Lakewood, CO 80215.*

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U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

July 2024

North Dakota Proposed Resource Management Plan and Final Environmental Impact Statement

***Volume 1** (Chapters 1-4, References, Glossary, Index)*

Prepared by:

US Department of the Interior
Bureau of Land Management

STATE OF NORTH DAKOTA
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Drew H. Wrigley
ATTORNEY GENERAL

May 22, 2023

SUBMITTED ONLINE VIA:
https://eplanning.blm.gov/eplanning-ui/project/1505069/510.

Sonya Germann
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United States Bureau of Land Management
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Kristen Braun
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United State Bureau of Land Management
North Dakota Field Office
99 23rd Ave. West, Suite A
Dickinson, ND 58601

Re: Notice of Availability of the Draft Resource Management Plan and Draft Environmental Impact Statement for the North Dakota Field Office [L16100000.DP0000 LX.SS.E0900000] (88 Fed. Reg. 3757 (Jan. 20, 2023)).

Dear Ms. Germann and Ms. Braun:

On January 20, 2023, the Bureau of Land Management ("BLM") announced the proposed revisions to the North Dakota Resource Management Plan entitled "*Notice of Availability of the Draft Resource Management Plan and Draft Environmental Impact Statement for the North Dakota Field Office*" (88 Fed. Reg. 3757) (hereinafter the "North Dakota RMP Proposal"). On April 4, 2023, State Director Sonya Germann extended the comment deadline for the North Dakota RMP Proposal by 30 days until May 22, 2023.

The State of North Dakota ("North Dakota" or the "State") respectfully submits these comments in response to the North Dakota RMP Proposal. The reasonable development of the natural resources on public lands located in North Dakota is an essential feature of the Federal Land and Policy Management Act ("FLPMA"), the Mineral Leasing Act ("MLA") and the resource management plans ("RMPs") that are developed under those statutes. That includes the 1988 BLM RMP for North Dakota that we have relied on substantially to provide affordable energy security to the nation.

North Dakota has serious concerns with BLM's preferred Alternative B and Alternative C in the North Dakota RMP Proposal. As set forth herein, Alternatives B and C would withdraw large portions of public lands in North Dakota from mineral development. Alternatives B and C would also effectively strand significant acreage of State and private lands due to North Dakota's unique of other minerals. Under both FLPMA and the MLA, BLM does not have authority to impose these blanket surface restrictions, especially for State or private lands or those lands managed by other agencies such as the U.S. Forest Service ("USFS") and the U.S. Army Corps of Engineers ("Corps"). BLM's North Dakota RMP Proposal is therefore irreconcilable with Congress' clear statutory direction in Section 184a of the MLA that the federal government cannot preempt a State's sovereignty over State, private, and State Trust Lands.

Alternatives B and C also proposes to unlawfully and selectively elevate conservation and other social and scientific values in violation of FLPMA's multiple use mandate. Under both FLPMA and the MLA, BLM does not have authority to promote conservation over mineral development or management.

Finally, Alternatives B and C are based on significantly flawed assumptions regarding the future development of mineral resources in North Dakota. As shown herein, there will be continuing demand for both fluid and solid mineral development in North Dakota over the next 20 years. Restricting the development of minerals under Alternatives B and C will not change existing demand, and will only result in increased environmental impacts by forcing State and private minerals to be developed in a less efficient manner.

For these reasons as explained in detail in these comments, BLM must adopt Alternative A in the North Dakota RMP Proposal due to the significant legal and technical issues associated with Alternatives B and C. If BLM does not adopt Alternative A to the North Dakota RMP Proposal, BLM must substantially rework, revise, and repropose the preferred Alternatives B and C in the North Dakota RMP Proposal to comply with the requirements of the Administrative Procedures Act ("APA"), FLPMA, and the MLA. Additionally, BLM's North Dakota RMP Proposal must be modified to comply with the preliminary injunction recently issued in *State of North Dakota v. U.S. Dept. of Interior et al.,* 1:23-cv-00004 (D.N.D.), which found that BLM has failed to timely hold quarterly oil and gas lease sales under the MLA and ordered BLM to resume quarterly leasing and work through its existing backlog of pending nominated oil and gas parcels in the State. *See State of North Dakota,* 1:21-cv-00148, ECF No. 98, Order Granting, in Part, and Denying, in Part, North Dakota's Motion for Preliminary Injunction (March 27, 2023).

Any action taken by BLM must be consistent with the U.S. Constitution, must not conflict with the statutory cooperative federalism framework of FLPMA, the MLA, and U.S. Supreme Court precedent. BLM must respect (and not impair) the regulatory authority over State and private mineral resources and water resources that resides with North Dakota.

I. North Dakota's Interest in the North Dakota RMP Proposal.

North Dakota has effectively partnered with BLM for decades to meet the challenge of properly regulating mineral development by avoiding waste of such resources in the State, whether under federal or State jurisdiction. North Dakota is blessed with abundant natural resources that are of great importance to its citizens and that also benefit the entire nation. North Dakota is proud of its strong record of responsible stewardship. North Dakota agrees with the Administration's broad emphasis on using resources wisely and efficiently.

The State of North Dakota is ranked 3rd in the United States among all states in the production of oil and gas. North Dakota produces approximately 400 million barrels of oil per year and 1.1 trillion cubic feet of natural gas per year. Implementation of BLM's preferred Alternative B will result in severe adverse economic impacts to the State, in addition to the significant interference with North Dakota's sovereign State functions. For example, the anticipated loss in State revenue from royalties and taxes for oil and gas alone is estimated to be $34 million per year. The impact from this loss is expected to last through the entire 30-year development life of the Bakken. North Dakota's revenues from the gross production tax and oil extraction tax fund various programs through a series of 12 funds that each must reach a maximum before funds can be appropriated to the next fund in the series.

North Dakota is also the 10th largest coal producer in the United States, with an average production of approximately 27.5 million tons per year of lignite coal over the past several years. Nearly all of the lignite coal is used within the State at mine-mouth power generating facilities and the nation's only commercially operating coal gasification plant.

A. North Dakota's Unique Split Estate Land Ownership.

Mineral ownership of North Dakota lands upon which oil and gas development has occurred consists of approximately 85% private lands, 9% federal lands, and 6% state lands. Many of the private lands in North Dakota upon which oil and gas development has occurred are split estate lands, with more than 30% of the potential development on private surface involving federal minerals and therefore subject to BLM's proposal.

North Dakota has a unique history of land ownership that has resulted in a significant portion of the state consisting of split estate lands that will be adversely affected by the proposed rule. Unlike many western states that contain large blocks of unified federal surface and federal mineral ownership, the surface and mineral estates in North Dakota were at one time more than 97% private and state owned as a result of the railroad and homestead acts of the late 1800s. However, during the depression and drought years of the 1930s, numerous small tracts in North Dakota went through foreclosure.

The federal government, through the Federal Land Bank and the Bankhead Jones Act, foreclosed on many farms taking ownership of both the mineral and surface estates. Many of the surface estates were later sold to private parties with some or all of the mineral estates retained by the federal government. This resulted in a very large number of small federally-owned mineral estate tracts scattered throughout western North Dakota. Those federal mineral estates impact more than 30% of the oil and gas spacing units that are typically recognized as a communitized area ("CA") by BLM. There are a few large blocks of federal mineral ownership, for which the federal government has trust responsibility and also manages the surface estate through the USFS or the Bureau of Indian Affairs. These are on the Dakota Prairie Grasslands in southern McKenzie County and northern Billings County as well as on the Fort Berthold Indian Reservation. Even within those areas, federal mineral ownership is interspersed with a "checkerboard" of private and state mineral or surface ownership. Therefore, virtually all federal management of North Dakota's oil and gas producing region consists of some form of split estate.

B. North Dakota's State Trust Lands Ownership.

In 1889, Congress enacted the Enabling Act "to provide for the division of Dakota [Territory] into two states, and to enable the people of North Dakota, South Dakota, Montana, and Washington to form constitutions and state governments, and to be admitted into the union on an equal footing with the original states, and to make donations of public lands to such states." Act of February 22, 1889, Ch.180, 25 Statutes at Large 676. Section 10 of this Act granted sections 16 and 36 in every township to the new states "for the support of common schools." In cases where portions of sections 16 and 36 had been sold prior to statehood, indemnity or "in lieu" selections were allowed. In North Dakota, this grant of land totaled approximately 2.6 million acres.

In the Enabling Act, Congress expressly provided that these State Trust Lands "shall not be subject to preemption, homestead entry, or any other entry under the land laws of the United States, whether surveyed or unsurveyed, but shall be reserved for school purposes only." *Id.* at Section 10. State Trust Lands are managed through the North Dakota Department of Trust Lands.

The Enabling Act provided further land grants to the State of North Dakota for the support of colleges, universities, the state capitol, and other public institutions. Revenues are generated through the prudent management of trust assets, which assets include approximately 706,600 surface acres and nearly 2.6 million mineral acres. Article IX, Section 2 of the North Dakota Constitution provides that the "net proceeds of all fines for violation of state laws and all other sums which may be added by law, must be faithfully used and applied each year for the benefit of the common schools of the state and no part of the fund must ever be diverted, even temporarily, from this purpose or used for any purpose other than the maintenance of common schools as provided by law." The grant of State Trust Lands was thus given in trust and required the State, as trustee, to maintain the permanency of the assets acquired through the grant.

II. The North Dakota RMP Proposal is Not Consistent with Federal Law.

As set forth below, BLM's North Dakota RMP Proposal is not consistent with FLPMA and the MLA because it would unlawfully impair North Dakota's sovereign right to regulate its own State and private resources, including minerals and water rights.

A. The North Dakota RMP Proposal Would Unlawfully Close Lands Subject to an Existing Preliminary Injunction in North Dakota.

On July 7, 2021, the State of North Dakota filed suit against the Department of the Interior ("Interior"), the Secretary, BLM, and multiple BLM officials challenging their cancellation of quarterly oil and gas lease sales in North Dakota. *See State of North Dakota,* 1:21-cv-00148. North Dakota's case was later consolidated with North Dakota's second challenge to BLM's lease sale cancellations, filed to challenge additional quarterly lease sale cancellations that occurred in 2021 and 2022 after the filing of North Dakota's first case. *See State of North Dakota v. U.S. Dept. of Interior et al.,* 1:23-cv-00004 (D.N.D.). On March 27, 2023, the U.S. District Court in North Dakota entered a preliminary injunction against the Federal Defendants in that consolidated action, finding that the Federal Defendants had failed to timely hold quarterly lease sales under the MLA. *See State of North Dakota,* 1:21-cv-00148, ECF No. 98, Order Granting, in Part, and Denying, in Part, North Dakota's Motion for Preliminary Injunction (March 27, 2023).

Key to North Dakota's challenge and the District Court's holding was a discussion "of whether the Federal Defendants were derelict in their mandatory statutory duties to evaluate federal lands nominated for oil and gas leasing in North Dakota and correspondingly hold lease sales in 2021 and 2022." *Id.* at ¶ 2. The Court found BLM had violated its statutory duty to hold quarterly lease sale, enjoined and restrained BLM from implementing the "unlawful policy to disregard their statutory duty to appropriately plan for and complete their determination of whether nominated land was 'available' and 'eligible' on a timely, quarterly basis", and ordered BLM to (1) Analyze individual parcels nominated for lease sales in North Dakota according to their statutory requirements; (2) Make lawful determinations regarding the nominated parcels' availability and eligibility; (3) Complete those determinations in time for quarterly lease sales, as set forth in statute and regulations; and (4) When there are "available" and "eligible" lands, hold a lease sale in that quarter. *Id.* at ¶ 147. As the District Court observed, the "MLA does not permit the Federal Defendants to 'skip' a quarterly lease sale due to an agency's self-inflicted 'truncated' review period, a nationwide [National Environmental Policy Act ("NEPA")] analysis backlog, focused effort on a nationwide survey of emissions, or speculation that a parcel (let alone all parcels) fails to meet NEPA's requirements." *Id.* at ¶ 83.

Further, the District Court ordered that BLM was "ENJOINED and RESTRAINED from *de facto* withdrawing lands in North Dakota identified for oil and gas development in their respective RMPs without following the statutory procedures for public notice and comment as well as congressional notice, where appropriate. *See* 43 U.S.C. §§ 1714, 1732. See also 5 U.S.C. §§ 705, 706(1)." *Id.* Under the Court's Order, BLM is required to evaluate long-pending nominated lands for inclusion in future quarterly lease sale.

BLM cannot now by dint of the North Dakota RMP Proposal surreptitiously withdraw these long-pending nominated lands which are subject to a preliminary injunction and for which BLM must make eligibility and availability determinations. Doing so would circumvent the Court's order and findings that BLM has long delayed in its statutory duty to evaluate and include these nominated lands in quarterly lease sales. BLM must provide an accounting of how its North Dakota RMP Proposal Alternatives B, and C will effect all 811 North Dakota parcels upon which expressions of interest have been submitted that are listed on their National Fluids Lease Sale System. No nominated parcel GIS layer was included in the current North Dakota RMP Proposal, and the effects on these nominated parcels is unknown absent BLM providing that data.

B. The North Dakota RMP Proposal Violates FLPMA and the MLA Because it Seeks to Regulate Non-Federal Lands.

The North Dakota RMP Proposal seeks to regulate surface activities on non-federal lands, noting that "[s]tipulation decisions (such as applying an [No Surface Occupancy ("NSO")], a controlled surface use [CSU], or a timing limitation [TL]) apply to fluid mineral leasing and development of federal mineral estate underlying BLM-administered surface lands, *private lands, and state trust lands*." North Dakota RMP EIS, Volume 1 at 2-11 (emphasis added).

For example, the North Dakota RMP Proposal seeks to unlawfully impair all of the 2.6 million mineral acres of State Trust Lands by both stranding those lands from development where federal minerals are not leased, and imposing surface occupancy conditions that make it unfeasible to develop the minerals located on those State Trust Lands. North Dakota holds title to the surface and mineral estate of these lands. The North Dakota RMP Proposal would do the same to large amounts of State and private lands. North Dakota collects revenue from oil and gas development on State Trust Lands to support its public education system. *See* N.D.C.C. § 15-01-02. North Dakota further collects revenue from oil and gas development on State and private lands to support education and its general fund. BLM, however, does not have legal authority under FLPMA or the MLA to regulate or impair these private and State lands, especially State Trust Lands.

i. FLPMA Does Not Authorize BLM to Regulate Non-Federal Lands.

Congress defined "public lands" in FLPMA as "any land and interest in land owned by the United States within the several States and administered by the Secretary of the Interior through the Bureau of Land Management, without regard to how the United States acquired ownership[.]" 43 U.S.C. § 1702(e). This definition does not authorize BLM to regulate surface operations on lands owned entirely by private individuals or the State. The plain language of the Property Clause limits Congress' authority to make needful regulations pertaining to "Property of the United States." U.S. Const. art. IV, sec. 3, cl. 2. Recognizing that Congress' constitutional authority rests in governing federal land, a U.S. Circuit Court of Appeals has rejected the argument that federal jurisdiction extends to adjoining State Trust Lands under broad mandates in federal land management statutes. *Utah Native Plant Soc'y v. U.S. Forest Serv.*, 923 F.3d 860, 866-67 (10th Cir. 2019) ("[T]he Property Clause's plain language is not self-executing and does not itself grant [a federal land management agency] authority over [ ] State lands adjacent to the [National Forest].)"

Tellingly, FLPMA also draws clear distinctions that demonstrate that the BLM's authority is limited to federal interests. Section 1712(c)(8) recognizes that federal land planning should consider state air, water, noise, or other pollution standards that are applicable to federal lands. 43 U.S.C. § 1712(c)(9). Section 1732(b) also recognizes the role of States in managing wildlife resources as a function of their traditional state police powers. 43 U.S.C. § 1732(b); *Def. of Wildlife v. Andrus*, 627 F.2d 1238, 1249-50 (D.C. Cir. 1980) ("It is unquestioned that the States have broad trustee and police powers over wild animals within their jurisdictions[.]") (citation omitted). As noted in the comments herein, BLM's North Dakota RMP Proposal would unlawfully impair and block the development of State and private mineral resources in North Dakota by stranding those interests and making economic development without waste impossible. *See* Attachment A hereto (showing how BLM proposes to impose NSO requirements on substantial amounts of private surface lands thereby severely impairing development of these lands as well as development of adjacent North Dakota State Trust Lands).

ii. The MLA Also Does Not Authorize BLM to Regulate Non-Federal Lands.

The MLA also respects the State's exclusive jurisdiction over its private, State, and State Trust Lands by recognizing that development involving both federal interests and State interests requires State consent. For example, Section 184a provides,

> [A]ny State owning lands or interests therein acquired by it from the United States may consent to the operation or development of such lands or interests, or any part

> thereof, under agreements approved by the Secretary of Interior made jointly or severally with lessees or permittees of lands or mineral deposits of the United States or others, for the purpose of more properly conserving the oil and gas resources within such State.

30 U.S.C. § 184a.

Section 184a also states that "[s]uch agreements may provide for the cooperative or unit operation or development of part or all of any oil or gas pool, field, or area … and, with the consent of the State, for the modification of the terms and provisions of State leases for lands operated and developed thereunder[.]" *Id.* The Secretary's regulations on the "Inclusion of non-Federal lands" reinforce the MLA provisions:

> Where State-owned land is to be unitized with Federal lands, approval of the agreement by appropriate State officials must be obtained prior to its submission to the proper BLM office for final approval. When authorized by the laws of the State in which the unitized land is situated, appropriate provision may be made in the agreement, recognizing such laws to the extent that they are applicable to non-Federal unitized land.

43 C.F.R. § 3181.4(a).

BLM's North Dakota RMP Proposal is irreconcilable with Congress' clear statutory determination that the federal government cannot preempt the State's sovereignty over private, State, and State State Trust Lands. BLM's interpretation of its jurisdiction also disregards Section 184 of the MLA and its implementing regulations that requires the State's consent to enforce federal terms of conditions on State Trust Lands. *See* 30 U.S.C. § 184a; 43 C.F.R. § 3181.4(a).

C. The North Dakota RMP Proposal Violates the MLA by Unlawfully Intruding on Reserved State Police Powers over Oil and Gas Activities.

The MLA includes two savings clauses that demonstrate Congress did not intend for BLM to exercise exclusive federal jurisdiction over oil and gas operations. *See* 30 U.S.C. §§ 187, 189. Section 187 relates to BLM's leasing authority, identifies conditions that each federal lease shall include, and states "[n]one of such provisions shall be in conflict with the laws of the State in which the leased property is situated." 30 U.S.C. § 187. Next, Section 189 of the MLA, in its entirety, reads:

> The Secretary of the Interior is authorized to prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of this chapter, also to fix and determine the boundary lines of any structure, or oil or gas field, for the purposes of this chapter. Nothing in this chapter shall be construed or held to affect the rights of the States or other local authority to exercise any rights which they may have, including the right to levy and collect taxes upon improvements, output of mines, or other rights, property, or assets of any lessee of the United States.

30 U.S.C. § 189.

Section 181 of the MLA only applies to "lands containing [oil and gas] deposits owned by the United States." 30 U.S.C. § 181. No specific language in the MLA allows BLM to regulate non-federal land. Notably, Congress did not even make all federal lands subject to federal mineral leasing. Under the MLA, minerals subject to disposition on lands owned by the United States include "national forests" but exclude acquired lands, communities within national parks and monuments, and lands within the naval petroleum and oil-shale reserves. *Id.*

The State of North Dakota possesses police power to regulate its natural resources. *See, e.g., Wall v. Midland Carbon Co.*, 254 U.S. 300, 313-16 (1920) (upholding the State's police power to regulate natural gas). The State exercises this authority by regulating oil and gas activity on fee, State, and federal land in North Dakota, through the North Dakota Industrial Commission ("NDIC"). *See* North Dakota Century Code ("NDCC") Chapter 38-08 *et seq.*; North Dakota Administrative Code ("NDAC") Chapter 43-02-03.

The fee/fee/fed policy correctly recognizes that on non-federal lands "In fee/fee/federal situations, the BLM often has limited jurisdiction." North Dakota RMP Proposal EIS, Volume 1 at 3-181. Despite this limited jurisdiction, and as set forth in these comments, BLM's North Dakota RMP Proposal would effectively strand State and private mineral resources, blocking or impairing them from developments by closing or applying NSO stipulations to BLM lands interspersed with State and private lands. Where these BLM lands cannot be developed, the entire spacing unit those BLM lands are subject to also either cannot be developed, or cannot be developed economically without waste. *See* Attachment A, *supra* at Section II.B.i.

D. The North Dakota RMP Proposal Unlawfully Elevates "Conservation" as a "Use" in Violation of FLPMA.

The North Dakota RMP Proposal lists "conservation" as a use and identified BLM's role in the RMP Process. *See* North Dakota RMP EIS, Volume 1 at ES-1 ("BLM has identified four specific purposes that describe BLM's distinctive role in the North Dakota landscape: provide opportunities for mineral and energy development on BLM-administered lands, contribute to the conservation and recovery of threatened, endangered, and special status species, provide for recreation opportunities, and manage for multiple other social and scientific values."). This is especially problematic in Alternative B (BLM's preferred Alternative). *See id.* at ES-2 ("Alternative B is the most proactive in promoting conservation and recovery of threatened and endangered and other special status species, as well as protecting other social and scientific values.").

As BLM is well aware, FLPMA is a land use planning and management statute which "established a policy in favor of retaining public lands for multiple use management." *Lujan v. National Wildlife Federation*, 497 U.S. 871, 877 (1990). "Multiple use management" describes the task of striking a balance among the many competing uses to which land can be put, "including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and [uses serving] natural scenic, scientific and historical values." *Norton v. S. Utah Wilderness All.*, 542 U.S. 55, 58 (2004) (citing to 43 U. S. C. § 1702(c)). A second management goal, "sustained yield," requires BLM to control depleting uses over time, so as to ensure a high level of valuable uses in the future. *Id.* (citing to 43 U.S.C. § 1702(h)). "To these ends, FLPMA establishes a dual regime of inventory and planning. Sections 1711 and 1712, respectively, provide for a comprehensive, ongoing inventory of federal lands, and for a land use planning process that 'project[s]' 'present and future use,' § 1701(a)(2), given the lands' inventoried characteristics." *Id.* Under these mandates, "FLPMA identifies 'mineral exploration and production' as one of the 'principal or major uses' of public lands." *WildEarth Guardians v. Bernhardt*, 502 F. Supp. 3d 237, 241 (D.D.C. 2020) (citing to 30 U.S.C. § 1702(l) ("The term 'principal or major uses' includes, *and is limited to*, domestic livestock grazing, fish and wildlife development and utilization, mineral exploration and production, rights-of-way, outdoor recreation, and timber production.") (emphasis added)). FLPMA clearly directs the Secretary to promote "mineral exploration and production" during RMP development. 30 U.S.C. § 1702(l).

FLPMA does not authorize BLM to promote "conservation" as a principle or major "use" of public lands. In 2016, BLM attempted to promulgate a rule promoting "conservation" as a use of public lands. *See* Resource Management Planning, Final Rule (81 Fed. Reg. 89580 (Dec. 12, 2016) ("Planning 2.0 Rule"). However, on March 27, 2023, President Trump signed a resolution from Congress under the Congressional Review Act that vetoed BLM's Planning 2.0 Rule. Through this veto, Congress clearly pronounced that it did not authorize BLM to elevate conservation as a principal or major use of lands under FLPMA.

More recently, on April 3, 2023, BLM issued a proposed rule that appears to be a revised iteration of the Planning 2.0 Rule already rejected by Congress. *See* Conservation and Landscape Health, 88 Fed. Reg. 19583. Like the Planning 2.0 Rule, BLM's new proposed rule would again attempt to elevate conservation considerations in RMP planning. However, BLM cannot rely on this proposed rule which is not yet finalized, and still subject to a likely veto under the Congressional Review Act from Congress. In the interim, the efforts by BLM to advance conservation for land management determinations in the North Dakota RMP Proposal are unlawful.

E. The North Dakota RMP Proposal Creates Large-Tract Withdrawals in Violation of FLPMA.

Alternative B recommends several large tracts of lands to be withdrawn from locatable mineral entry. *See* North Dakota RMP Proposal EIS at 2-38 (Recommending "13,100 acres for withdrawal from locatable mineral entry."); *see id.* at 3-112 (Table 3-64 recommending approximately 35,000 acres be withdrawn); *id.* at 3-177 ("Under Alternative B, 8,300 acres would be recommended for withdrawal to protect known or proposed bighorn sheep crucial habitat, Doaks Butte, the Schnell Ranch SRMA, and the Mud Buttes ACEC.").[1] However, the Secretary's FLPMA authority to withdraw federal land in amounts over 5,000 acres is limited by Congress. 43 U.S.C. §1714(c)(1).

Congress retained a legislative veto over any such FLPMA large-tract withdrawal. *Id.* The U.S. Supreme Court determined that legislative vetoes are unconstitutional. *INS v. Chada*, 462 U.S. 919 (1983). Since FLPMA's legislative veto provision is integral to the Secretary's limited large-tract

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[1] Confoundingly, the North Dakota RMP Proposal EIS also states that "[t]here are no FLPMA withdrawals in the planning area. North Dakota RMP Proposal EIS at 3-173.

withdrawal authority, the provision's unconstitutionality under *Chada*, makes the entire large tract withdrawal provision invalid. The large tract withdrawals contemplated under Alternative B are left to Congress, not BLM. Accordingly, the Secretary lacks the authority to propose or make the recommended withdrawals in Alternative B.

F. The North Dakota RMP Proposal Would Unlawfully Impair Valid Existing Lease Rights.

Pursuant to FLPMA, all BLM actions, including authorization of RMPs, are "subject to valid existing rights." Thus, according to federal statute, BLM cannot terminate, modify, or alter any valid or existing property rights through a land use plan update process. This fundamental principle is found within the applicable statutes, regulations, and BLM policy guidance. As BLM is well aware, BLM's current 1988 RMP in North Dakota has engendered substantial State and private reliance interests.

Congress made it clear that nothing within the statute, or in the land use plans developed under FLPMA, was intended to terminate, modify, or alter any valid or existing property rights. Thus, an RMP update prepared pursuant to FLPMA, after lease execution, is likewise subject to existing rights.

Therefore, through the North Dakota RMP Proposal, BLM cannot revise or restrict valid existing lease rights through imposition of Conditions of Approval for drilling permits or through imposition of lease stipulation provisions from adjacent leases. BLM must make clear in any future RMP revisions that timing limitations, CSU and NSO stipulations, and any other management prescriptions across the planning area are not applied retroactively to existing leases. At this time North Dakota has identified multiple existing leases and areas that appear to be impacted in the North Dakota RMP Proposal. *See* Attachments B, C, and D hereto illustrating impaired leasing areas.

G. The North Dakota RMP Proposal Improperly Relies on Executive Order 13990 and the Social Cost of Greenhouse Gases.

The North Dakota RMP Proposal EIS provides "estimates of the monetary value of changes in [greenhouse gas ("GHG")] emissions that could result from selecting each alternative" under a social cost of GHG ("SC-GHG") analyses, despite noting that "2016 GHG Guidance noted that NEPA does not require monetizing costs and benefits." North Dakota RMP Proposal EIS, at 3-22. This is despite the EIS recognizing that its SC-GHG figures "do not constitute a complete cost-benefit analysis, nor do the SC-GHG numbers present a direct comparison with other impacts analyzed in this document. The SC-GHG is provided only as a useful measure of the benefits of GHG emissions reductions to inform agency decision-making" and that "there are multiple sources of uncertainty inherent in the SC-GHG estimates." *Id.*

The North Dakota RMP Proposal purports to rely on SC-GHG estimates based on "Section 5 of Executive Order 13990" which directs agencies to "capture the full costs of greenhouse gas emissions as accurately as possible, including by taking global damages into account." *Id.*; *see also* Executive Order 13990, *Protecting Public Health and the Environment and Restoring Science* *to Tackle the Climate Crisis*, 86 Fed. Reg. 7037 (Jan. 25, 2021). However, Executive Order 13990 is not binding law, and cannot contradict the statutory mandates that govern BLM's actions.

Further, by its own terms Executive Order 13990 states that it "shall be implemented in a manner consistent with applicable law." 86 Fed. Reg at 7042. Similarly, Executive Order 13990 notes that "[t]his order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States." *Id.* at 7043. The goal stated in Executive Order 13990 "that agencies capture the full costs of greenhouse gas emissions as accurately as possible" does not alter existing NEPA or FLPMA requirements and does not create any enforceable rights, particularly where BLM seeks to rely on the goals from Executive Order 13900 to justify withdrawing lands that FLPMA's multiple use mandate would otherwise require to be managed otherwise.

Similarly, the 2016 GHG Guidance for which BLM relies on in incorporating its SC-GHG estimates (*see* EIS at 3-21 – 3-22) notes that "[t]his guidance is not a rule or regulation, and . . . does not change or substitute for any law, regulation, or other legally binding requirement, and is not legally enforceable."). The new 2023 GHG guidance contains identical language. As *guidance* documents, BLM cannot rely on either Executive Order 13990 or the 2016/2023 GHG Guidance documents to circumvent its multiple-use and sustained yield mandates under FLPMA to promote the development of mineral resources as a principal and major use of public lands.

H. The North Dakota RMP Proposal Seeks to Obtain Water Rights in Violation of North Dakota Law.

The North Dakota RMP Proposal directs BLM to "[a]cquire and perfect federal reserved water rights necessary to carry out BLM-administered land management purposes" and states that "[i]f a federal reserved water right is not available, then acquire, perfect, and protect water rights through state law." North Dakota RMP Proposal EIS at 2-17. While the North Dakota RMP Proposal EIS recognizes that BLM should perfect water rights according to North Dakota law, Alternative B has a focus on managing "surface water and groundwater quality on BLM-administered lands to protect, maintain, improve, and/or restore the chemical, physical, and biological integrity of waters to protect beneficial uses" and to "[p]rotect, restore, and maintain the chemical, physical, and biological (ecological) services of surface water and groundwater to support resource management needs and all associated beneficial use standards." *Id.*

However, under North Dakota law, these conservation goals are not recognized as a beneficial use of North Dakota's sovereign state waters. North Dakota's Constitution, Article XI, § 3 states: "All flowing streams and natural watercourses shall forever remain the property of the state for mining, irrigating and manufacturing purposes."

BLM's Alternative B does not comply with North Dakota's sovereign right to regulate its waters because it would assert jurisdiction over State managed and permitted water through the permitting conditions and stipulations in the North Dakota RMP Proposal that target North Dakota's waters through NSO stipulations designed around conservation of State waters. However, it is inappropriate and contrary to North Dakota's sovereign right to regulate State waters to impose stipulations on waters inconsistent with the State's beneficial use standards.

I. The North Dakota RMP Proposal is Not Governed by the District of Montana's Decisions in *Western Organization of Resource Council v. BLM.*

During discussions between North Dakota and BLM officials on May 17 2023, BLM indicated that Alternative B's proposal restrict coal leasing outside of existing mining permit area (Alternative B.1) or within 4 miles of an existing permit area (Alternative B) was required by the recent *Western Organization of Resource Council v. BLM* decision in the United States District Court for the District of Montana. *See Western Organization of Resource Council v. BLM*, 2022 WL 3082475 (D. Mont. Aug. 3, 2022); *Western Organization of Resource Council v. BLM*, CV 16-21, Not. Rep. F. Supp. (D. Mont. Mar. 3, 2018).

North Dakota disagrees with those assertions. First, the decision in the *Western Organization of Resource Council v. BLM* cases are not preclusive in North Dakota as they are from another, non-binding District Court. Second, those decisions only found that BLM failed to consider a reasonable range of alternatives for coal leasing, including "lower end" alternatives that would more significantly restrict coal leasing. *See Western Organization of Resource Council v. BLM*, 2022 WL 3082475 at *5-6. What these court decisions specifically did not require, however, was a specific 4-mile buffer. As set forth in the North Dakota PSC's comments, the 4 mile buffer does not comply with FLPMA's or the MLA's requirement for mixed use development, nor is it based on a reasoned BLM policy. BLM's decision to drastically reduce coal leasing opportunities in Alternative B is simply not consistent with FLPMA or the MLA.

III. North Dakota State Agency Specific Comments.

A. North Dakota Industrial Commission Comments on the North Dakota RMP Proposal.

The NDIC was created by the North Dakota legislature in 1919 to conduct and manage, on behalf of the State, certain utilities, industries, enterprises and business projects established by State law. One of the NDIC's many areas of jurisdiction includes overseeing the Department of Mineral Resources, Oil and Gas Division.

The NDIC, Department of Mineral Resources, Oil and Gas Division regulates the drilling and production of oil and gas in North Dakota. The agency's mission is to encourage and promote the development, production, and utilization of oil and gas in the State in such a manner as will prevent waste, maximize economic recovery, and fully protect the correlative rights of all owners to the end that the landowners, the royalty owners, the producers, and the general public realize the greatest possible good from these vital natural resources.

The NDIC, Oil and Gas Division has jurisdiction to administer North Dakota's comprehensive oil and gas regulations found at NDAC Chapter 43-02-03. These regulations include regulation of the drilling, producing, and plugging of wells; the restoration of drilling and production sites; the perforating and chemical treatment of wells, including hydraulic fracturing; the spacing of wells; operations to increase ultimate recovery such as cycling of gas, the maintenance of pressure, and the introduction of gas, water, or other substances into producing formations; disposal of saltwater and oil field wastes through the North Dakota Underground Injection Program; and all other operations for the production of oil or gas.

The NDIC has significant concerns with Alternative B to the North Dakota RMP Proposal.

First, the North Dakota RMP Proposal seeks to close large areas of subsurface for mineral development in the vicinity of USFS managed surface lands which have recently been found to be open for leasing (either with no surface restrictions or with some surface restrictions). The closure of these BLM managed lands effectively block the development of the USFS managed lands, despite the USFS having recently determined these lands were appropriate for mineral development in their respective RMPs finalized in the last three years. *See* Northern Great Plains Management Plans Revisions, Final Supplemental Environmental Impact Statement for Oil and Gas Leasing (December 2020); *see also* Garrison Dam/Lake Sakakawea Project Oil and Gas Management Plan (June 2020) (showing Corps lands impacted).

For example, the North Dakota RMP Proposal will close 103,918 acres of BLM subsurface to fluid mineral leasing. These 103,918 closed acres are in the direct vicinity of various acres of USFS managed lands under their respective RMPs which have <u>not</u> been closed to development and thus impacts the ability to develop those USFS managed lands. The lands proposed to be closed by BLM under Alternative B, thus impairing USFS lands includes:

- 2,000 acres incidental to Steep Slopes.
- 45,800 acres incidental to Sensitive Soils.
- 2,900 acres incidental to Badlands.
- 359 acres incidental to Water Resources and not designed to directly protect the water resource.
- 8,259 acres BLM subsurface closed for Fish and Aquatic Species.
- 15,600 acres BLM subsurface closed for Paleontology Resources.
- 14,000 acres within 22 miles ephemeral streams closed to leasing

All of these interests are directly adjacent to USFS managed lands which have <u>not</u> been closed to mineral leasing in the USFS's recent RMP decision. Due to the adjacency of these BLM managed closed lands, it is not economically feasible for North Dakota to develop the USFS managed lands due to the split estate nature of minerals in North Dakota and established spacing units. Essentially, lateral wells cannot be efficiently and economically drilled to allow the development of the USFS lands in the vicinity of these closed BLM subsurface minerals.

Second, the North Dakota RMP Proposal seeks to impose significant surface restrictions that either impair the development of adjacent USFS managed surface estates or directly contradicts with the surface requirements of USFS managed surface estates. In the North Dakota RMP Proposal, BLM has proposed to add NSO stipulations to 159,500 acres of BLM managed surface estates. The USFS' recent Northern Great Plains Management Plans Revisions, completed in 2020, only applied NSO restrictions to 118,500 acres of USFS managed surface estates. Despite managing substantially less surface estates, BLM is proposing to add NSO stipulations to approximately 41,000 more acres of surface estates.

Further, BLM's NSO determinations directly conflict with areas under the USFS jurisdiction, including:

- 48,100 acres BLM subsurface NSO for Badlands (conflicting with recent USFS determinations).
- 52,900 acres BLM subsurface NSO for vegetation (conflicting with recent USFS determinations).
- 58,500 acres BLM subsurface NSO within 3 miles of historic properties (conflicting with recent USFS determinations).
- 18,500 acres within 29 miles of ephemeral streams having NSO designations, conflicting with USFS and Corps determinations).

BLM's North Dakota RMP Proposal does not provide adequate data for North Dakota to complete a parcel-by-parcel analysis to determine which USFS managed surface lands are directly impacted. However, based on the decision area totals North Dakota believes that USFS managed surface estates are directly impacted by BLM's surface restrictions. At a minimum, BLM must develop maps or tables that directly compare their restrictions to USFS 2020 ROD stipulations by parcel.

The North Dakota RMP Proposal contains no explanation as to why BLM is attempting to require additional surface disturbance requirements and contradict the recent decisions by the USFS that such surface disturbance requirements are not necessary. Nor does the North Dakota RMP Proposal explain how the USFS should deal with these contradictory requirements. Lastly, BLM's North Dakota RMP Proposal also lacks defined criteria for operators to obtain a modification or waiver of a restriction where these requirements differ. The NDIC's position is that the recently promulgated USFS RMP should control and be given precedence over the North Dakota RMP Proposal where there are conflicts.

Third, the Reasonably Foreseeable Development ("RFD") Scenario for Oil and Gas Development (May 2022) understates future potential development as a result of several flawed assumptions:

1. That the Bakken-Three Forks is the only target for high and medium potential development.
2. That any acreage outside of a five-mile buffer from oil and gas fields that had been active in the last 10 years has a low development potential. No technological or regulatory changes will impact the viability or rate of Bakken or Three Forks development in the next 20 years. Negating the impact of technological advancements is overly pessimistic and is contrary to past experience, which has shown that advancements in drilling and completions techniques can dramatically increase the viability of oil and gas development opportunities.
3. That BLM did not consider resources in other oil and gas bearing formations. Twenty different formations have commercially produced oil and/or gas within North Dakota. In 2006, the Bakken-Three Forks came into prominence following the discovery of the Parshall Field in western North Dakota. Following discovery of the Parshall Field (2007-present), more than 680 oil and gas wells have been drilled, completed, and produced oil and gas from North Dakota rock units other than the Bakken-Three Forks Formations. This

> includes approximately 280 new productive non-Bakken/Three Forks wells drilled during the past 10 years (2013-present). Exploration and development in formations other than the Bakken-Three Forks has been ongoing and is expected to continue.

Fourth, BLM's North Dakota RMP Proposal has not adequately explored the potential for geothermal development in North Dakota. Deep Earth Energy Production is developing a geothermal facility just a few miles north of the North Dakota border in southern Saskatchewan, Canada. The DMR-Geological Survey has also recorded temperatures up to 300 F in 13,000-foot-deep oil wells in the Interlake Formation in McKenzie County. Neither of these potential resources appears to have been addressed in the North Dakota RMP Proposal. Separately, the removal of lithium from formation waters or from produced waters is actively being pursued in southeastern Saskatchewan by Prairie Lithium and companies are currently investigating its potential in North Dakota.

Fifth, as explained above, the North Dakota RMP Proposal is seeking to withdraw lands that are already proceeding through the leasing process – expressions of interest have been received by BLM, and BLM has been sitting on processing those nominated lands for several years. BLM does not provide a basis for removing these lands that have already been found suitable for development under the 1988 North Dakota RMP and the recent Corps and USFS RMPs. Further, this raises significant legal concerns for North Dakota – BLM has been ordered by a North Dakota Federal District Court to proceed with leasing in North Dakota, including working through the backlog of previously nominated lands. *See State of North Dakota,* 1:21-cv-00148, ECF No. 98, Order Granting, in Part, and Denying, in Part, North Dakota's Motion for Preliminary Injunction (March 27, 2023). BLM has been found to have been deficient in processing long-pending lands for quarterly lease sales in North Dakota, and BLM cannot collaterally attack that existing preliminary injunction order by withdrawing lands from the North Dakota RMP Proposal that it is under a legal obligation in North Dakota to proceed with leasing.

Sixth, the low, moderate, and high potential designations in the North Dakota RMP Proposal are fundamentally flawed because they do not account for available technical data that do not support BLM's designations. The following studies demonstrate that BLM's determination of high, moderate, and low potentials for development are flawed and not based on current data.

- GI-241 Spearfish Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment E hereto);
- GI-240 Tyler Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment F hereto);
- GI-239 Madison Group Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment G hereto);
- GI-238 Bakken Petroleum System Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment H hereto);
- GI-237 Birdbear Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment I hereto);
- GI-236 Duperow Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment J hereto);

- GI-235 Dawson Bay Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment K hereto);
- GI-234 Winnipegosis Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment L hereto);
- GI-233 Interlake Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment M hereto);
- GI-232 Stonewall, Stony Mountain and Gunton Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment N hereto);
- GI-231 Red River Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment O hereto);
- GI-230 Deadwood and Winnipeg Production and Drill Stem Test Summary: Stolldorf, T.D., 2020 (Attachment P hereto);
- GI-222 Review of Production, Completions, and Future Potential of the lower Tyler Formation – Central Williston Basin, North Dakota: Nesheim, T.O., 2019 (Attachment Q hereto);
- GI-214 Stratigraphic and Structural Relations of the Birdbear Formation (Devonian), Western North Dakota: Bader, J.W., 2018. (Attachment R hereto);
- GI-213 Spatial distribution of elevated oil saturations within the Midale subinterval (Mississippian Madison Group), Burke County – North Dakota: Nesheim, T.O., 2018 (Attachment S hereto);
- GI-210 Review of Hydrocarbon Production from the Stonewall and lower Interlake Formations: Western North Dakota - Williston Basin. Nesheim, T.O., 2018 (Attachment T hereto);
- GI-191 Hydrocarbon Generation Significance of Kukersites, the Prospective Petroleum Source Beds of the Red River Petroleum System – Williston Basin, North America. Nesheim, T.O., 2016 (Attachment U hereto);
- GI-186 Stratigraphic Correlation and Geochemical Analysis of Kukersite (Source Rock) Beds within the Ordovician Red River Formation, Southwestern North Dakota. Nesheim, T.O., Nordeng, S.H., and Bader, J.W. 2015 (Attachment V hereto);
- GI-180 Beaver Creek Anticline, West-Central North Dakota. Nesheim, T.O., 2014. North Dakota Geological Survey, Geologic Investigations No. 180 (Attachment W hereto);.
- GI-178 Activation Energies and RockEval Analyses of Kerogenites in the Red River Formation in North Dakota. Nordeng, S.A., 2014 (Attachment X hereto);[2]

Based on the foregoing North Dakota Geological Survey investigations that constitute Resource Management Planning Studies, North Dakota has identified the following areas of High to Very High Potential that are very likely to see fluid mineral development and an area of Moderate Potential that may see fluid mineral development during BLM's stated 20 year lifetime of the North Dakota RMP Proposal. *See* Map of High, Moderate, and Low Potential Development Areas, Attachment Y hereto.

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[2] Summaries of each drill stem test study are attached to these comments. Full DST Maps, production maps, well lists, and GIS data are incorporated by reference to the State of North Dakota's comments and are available at: https://www.dmr.nd.gov/ndgs/Publication_List/gi.asp. Some files may require GIS or other mapping related software to open.

B. The North Dakota Department of Trust Lands Concerns with the North Dakota RMP Proposal.

The Board of University and School Lands ("Board") is established by North Dakota's State Constitution and charged with managing Trust Lands in a way that is in the best interest of the trusts' beneficiaries. The Board is comprised of the Governor, Secretary of State, Attorney General, State Treasurer, and Superintendent of Public Instruction. Under State law, the Board has "[f]ull control of the . . . . management of . . . . [l]ands donated or granted by or received from the United States or from any other source for the support and maintenance of the common schools." N.D.C.C. § 15-01-02.

In 2011, the Board adopted the name "Department of Trust Lands" as the common reference for the office of the Commissioner. Prior to that time, it was informally called the "State Land Department." The North Dakota Department of Trust Lands is the administrative arm of the Board, serving under the direction and authority of the Board. The Department manages approximately 2.6 million mineral acres with their approximate 8,700 associated oil and gas leases, and over 700,000 surface acres with their approximate 4,400 associated agricultural leases. Revenues generated from these leases, along with payments received from other income sources such as oil & gas lease bonus payments and easements granted for pipelines, roads, and well pads, are deposited into 13 permanent trust funds and invested to provide long-term income for trust beneficiaries. For example, most of the land managed by the North Dakota Department of Trust Lands is associated with the Common Schools Trust Fund. The sole beneficiaries of the assets held in the Common Schools Trust Fund, including the land and all revenue generated from these assets, are the common schools of the State. Thus, the State of North Dakota is federally mandated to manage Trust Lands in a manner consistent with the fiduciary intent of the Enabling Act of 1889.

BLM's North Dakota RMP Proposal impairs the North Dakota Department of Trust Land's ability and fiduciary responsibility to manage Trust Lands in the best interest of the trusts' beneficiaries and fails to equally consider all policies of FLPMA in several ways.

First, the North Dakota Department of Trust Lands has fiduciary obligations to manage State-owned Trust Lands in a manner that is in the best interest of trust beneficiaries. Section 2.4 of the North Dakota RMP Proposal states that "[s]tipulation decisions . . . . apply to fluid mineral leasing and development of federal mineral estate underlying BLM-administered surface lands, *private lands, and state trust lands*." RMP EIS, Volume 1 at 2-11 (emphasis added). The North Dakota RMP Proposal would impose management decisions involving State Trust Land. Yet BLM is not subject to the same fiduciary responsibilities of the North Dakota Department of Trust Lands, as set forth in the North Dakota State Constitution. Management decisions of BLM may be contrary to the benefit of trust beneficiaries which would be a direct transgression from the purpose of Trust Lands as set forth in the Enabling Act of 1889.

North Dakota's interest is closely intertwined with the interests of the Federal Government due to the intermixed ownership of State and BLM-managed lands located throughout western North Dakota. There is also a great deal of private fee-owned lands located in these same areas. In many cases, State Trust Lands are completely landlocked by federal lands. Thus, any limitation on mineral development in adjacent federally-owned tracts will result in an adverse economic impact on North Dakota by blocking the development of Trust Lands.

An example of the federal leasing restrictions directly impacting the development of State-owned mineral interests is Section 16 in Township 148 North, Range 95 West, McKenzie County, North Dakota (*See* Attachment Z hereto). Attachment Z depicts the location of 469.49 acres of mineral interest owned by North Dakota. This particular interest is situated in a very productive area of the Bakken Oil Field. Due to the restrictions placed on the surrounding acreage by the federal government, the land and minerals, granted to the North Dakota through the Enabling Act at statehood, is not being developed. Under BLM's North Dakota RMP Proposal the minerals under Section 16 might never be developed. The impact of these federal restrictions is contrary to the intent for which the United States granted Trust Lands to North Dakota. Restricting federally-owned lands that are within the vicinity of State-owned Trust Lands deprives the State the ability to continue to utilize these assets to maintain the Common Schools Trust Fund and consequently erodes the value of the lands in question. While there are many other State-owned lands and State Trust Lands that would be impacted by this North Dakota RMP Proposal, the value of lost revenue for North Dakota in Section 16 alone is estimated to at least $50 million.

Another example of where BLM's North Dakota RMP Proposal would impose restrictions on federally owned lands and adversely impact the State's ability to manage State Trust Lands is Sections 27 and 34, Township 151 North, Range 95 West, McKenzie County, North Dakota. Like the example above, this is a highly--productive area located in the heart of the Bakken Oil Field. The unleased minerals, combined with the restrictions on surface locations, have made it impossible for the State's minerals interests to be developed. Delays and moratoriums caused by federal restrictions not only affect the royalties that would be paid to the applicable trust funds, but also deprive the State the opportunity to invest those royalties which over time would generate a significant rate of return for its beneficiaries.

As further example, North Dakota owns 4,000 acres (depicted in Attachment AA hereto) across Sections 13, 14, 15, 16, 21, 22, 23, and 24 in Township 141 North, Range 101 West, Billings County, North Dakota. There are several existing legacy wells located on these lands that are currently producing oil. The area, while further away from the Tier 1 acreage, maintains significant development opportunity using the current horizontal technology with a 1,920--acre spacing unit. The restrictions proposed in the BLM's Alternatives B and C, including NSO, restricted drilling times, or the ability to construct pipelines or roads, will adversely impact any significant development in this area. Even if the restrictions are only placed on the surrounding federal-owned lands, the impact of those restrictions together with the NSO would be catastrophic to any future development of those State Trust Lands.

Second, while oil and gas production continue to be an important industry in North Dakota, coal development also remains a critical part of the North Dakota power grid and economy. In Mercer and Oliver Counties, the Department of Trust Lands has approximately 90 active coal leases. The North Dakota RMP Proposal, particularly Alternatives B and B.1 as depicted in Attachment BB hereto, would completely decimate the value of North Dakota's coal value in those areas. Though BLM estimates that there is ample leased State and fee lands available to the existing coal mines through 2040, the North Dakota PSC disputes that these lands will be able to be mined due to the nature of the mines themselves. Due to the intermingled "checkboard" ownership in this area, the development of these resources would be greatly impacted. The mines themselves need to have a contiguous pattern allowing for consistent economic production. For example, under the North Dakota RMP Proposal, NSO 11-63 would prohibit surface occupancy and use in an authorized federal coal lease existing prior to the time the oil and gas lease was issued. This is an unlawful impairment of existing leases. Further, under the North Dakota RMP Proposal, many of the State's smaller tracts would again be stranded due to the surrounding federal lands.

Third, along with the concerns about oil, natural gas, and coal, North Dakota's rare earth deposits have been proven to be an answer to our nation's problem in securing critical rare earth minerals. The Energy Act of 2020 defines a "critical mineral" as a non-fuel mineral or mineral material essential to the economic or national security of the United States and which has a supply chain vulnerable to disruption. Recent tests developed by the University of North Dakota Energy & Environmental Research Center and the North Dakota Industrial Commission have shown the presence of developmental amounts of lithium, and other critical minerals needed to make batteries, cell phones, and other technology. The greatest concentrations of these critical minerals are located in Dunn, Slope, Mercer, and Oliver Counties, the same counties that produce North Dakota's coal. *See* Attachment CC hereto, Elevated Critical Mineral Concentrations Associated with the Paleocene-Eocene Thermal Maximum Golden Valley Formation, North Dakota. In fact, the coal produced in this area has shown a presence of minable content of lithium. The BLM's North Dakota RMP Proposal would further restrict North Dakota's and the nation's ability to develop these critical resources at the time when they are now most needed. The ancient subtropical soils in these areas may hold the key to critical mineral enrichment in the Williston Basin of North Dakota.

In addition to mineral interests, the Department of Trust Lands also manages over 700,000 surface acres. These acres provide multiple avenues of revenue for the trusts including agricultural leasing, encumbrances, and aggregate mining. The Department must retain flexibility in how the lands are managed to ensure that these lands continue to generate revenue to maintain the State's public institutions. Approximately 5,200 acres of surface interest is located with BLM-managed fluid minerals and 8,500 acres of surface interest with BLM-managed coal minerals. According to Section 2.4 of the North Dakota RMP Proposal, these lands are subject to restrictions from BLM management which would adversely impair the Department of Trust Land's fiduciary and sovereign obligations to develop these resources.

Finally, the North Dakota RMP Proposal disproportionately focuses on conservation and maintaining air quality at the expense of other uses of BLM-managed lands in violation of FLPMA's multiple use mandate and stated principal and major use for mineral development.

The effect of BLM's North Dakota RMP Proposal is to significantly deprive the State's Trust Lands of their value by effectively prohibiting development of Trust Lands. Thus, the ability of the State of North Dakota to achieve income to adequately fund K-12 public education will be permanently harmed. Such an outcome is not consistent with the Enabling Act of 1889. Furthermore, this may be considered a taking in many circumstances.

C. North Dakota Public Service Commission's Concerns with the North Dakota RMP Proposal.

The North Dakota Public Service Commission ("North Dakota PSC") is a state constitutional agency with varying degrees of authority over, among other things, electric and gas utility regulation, energy transmission and generation siting consistent with minimal impacts on the environment and public welfare, surface coal mining and reclamation, and the elimination of hazards from abandoned mine lands.

The North Dakota PSC's regulation of the coal mining industry began in North Dakota in 1970. After the enactment of the Surface Mining Control and Reclamation Act of 1977 ("SMCA"), the State entered into a Federal-State cooperative agreement ("Cooperative Agreement") with the U.S. Department of Interior's Office of Surface and Mining. Federal-State Cooperative Agreement. Surface Mining Control and Reclamation Act (Federal Act), Pub. L. 95-87, 30 U.S.C. 1273(c). The Cooperative Agreement authorizes North Dakota PSC regulation of surface mining and reclamation operations on private and Federal lands within North Dakota, consistent with State and Federal Acts and the Federal lands program. In short, the North Dakota PSC is the primary authority over the development of surface coal mining operations and reclamation within the State.

Approximately 144,000 acres have been put under State permit since that time and over 27,000 of those acres have been released completely from performance bond. As of June 30, 2016, a total of 133,527 acres have been permitted, with approximately 78,013 (58%) disturbed by mining activity to date. Of these disturbed acres, approximately 54,094 acres have been backfilled, graded, top-soiled and seeded (or 69% of the lands disturbed have been reclaimed to the point of establishing vegetation). Since 1980, North Dakota's regulatory program has been a partnership effort between the State and the U.S. Department of the Interior's Office of Surface Mining. At present, 64% of program costs are borne by the Department of the Interior. The remaining 36% comes from funds appropriated by Congress.

The North Dakota PSC is opposed to BLM's North Dakota RMP Proposal due to BLM's abandonment of the multiple use mandate required by FLPMA, the divergence from the established policy in the existing 1988 North Dakota RMP on which the State has long relied to plan environmentally sound mineral development, and the incomplete and flawed analysis by which BLM justifies its proposal. The North Dakota PSC has found that the North Dakota RMP Proposal will significantly and adversely restrict the efficient development of coal and frustrate the North Dakota PSC's authority to limit environmental impacts and encourage orderly development in the State. As such, the North Dakota PSC is opposed to Alternative B and urges BLM to adopt Alternative A in the North Dakota RMP Proposal.

i. BLM's North Dakota RMP Proposal has Not Provided Adequate Justification for its Selection of Coal Screens and Inappropriately Applies Restrictions Better Left for Implementation Level Lease Planning.

FLPMA provides that BLM shall "develop maintain, and when appropriate, revise land use plans." 43 U.S.C.A. § 1712. RMPs are the first tier of land use planning in the two tiered BLM planning process. *See* Scoping Report, November 2020, Resource Management Plan and Environmental

Impact Statement, Prepared by the U.S. Dept. of the Interior Bureau of Land Management. Pg. 7, 1.1. RMPs provides planning-level management strategies that are to be expressed in the form of goals, objectives, allowable uses, management actions, and resource uses. *Id.* RMPs also provide broad direction and guidance for resources. Due to the indefinite period in which a decision area may be subject to a RMP, any first tier planning level strategies should be supported with a high level of certainty. Planning and management decisions for more limited geographic units of BLM-administered lands should be deferred to a more detailed site-specific implementation planning and NEPA analysis where data may be defined and applied.

BLM is required to implement screening procedures to identify designated areas for leasing consideration. 43 C.F.R. § 3420.1-4. The screens designated for RMPs are: (1) Identify coal with development potential; (2) Application of unsuitability criteria; (3) Multiple use conflict analysis; and (4) Surface owner consultation. These screens are not an authorization for BLM to materially impair existing mines and elevate conservation in the FLPMA planning process. It is therefore inappropriate for BLM to apply the coal screens in the North Dakota RMP Proposal in a manner that materially incumbers development of federal coal for future owners.

Coal Screen 2 provides a number of criteria that appear to be adequately substantiated for unsuitability. Areas such as public roadways, public buildings, state parks, national historic trails, incorporated cities, listed historical sites, and other federally designated areas are the type of land uses that are appropriately screened. However, several criterions were applied with incomplete data or require additional verification to their unsuitability. For example, Maps F-11 and F-12, Screen 2 Unsuitability – Criterion 9, incorrectly indicates that federally designated critical habitat for the whooping crane exists in the decision area and that designated critical habitat for the Dakota skipper exists in Dunn and Oliver Counties. The U.S. Fish and Wildlife Service has not formally designated critical habitat for the whooping crane and Dakota Skipper in North Dakota's coal producing counties. *See* Attachment DD hereto.

Coal Screen 3 provides that land use decisions may be made to protect other resource values and land uses that are "regionally or nationally important or unique", such as air and water quality, wetlands, and riparian areas. 43 C.F.R. 3420.1-4. This elevates conservation in BLM's North Dakota RMP Proposal over mineral development, a result not allowed by FLPMA. Despite BLM's North Dakota RMP Proposal acknowledging that no national air quality standards were exceeded, Coal Screen 3 sets forth a geographic limitation based upon a thinly-deduced reduction of GHG emissions from reduced transportation needs from existing mines and other associated GHG emissions. Rather than careful balancing for multiple use, Coal Screen 3 provides for a dramatic elimination of federal subsurface coal leasing without consideration of whether the human environment may be benefitted by subsurface coal lease development and instead largely bases elimination of future federal coal leasing upon an incorrect assumption of reduced GHG emissions.

There is no rational basis for an RMP level elimination of potential federal coal leasing without ground-truthing and operational understanding of the specific mineral and surface use effects. This type of evaluation can only be done on an implementation level as leases are issued, with appropriate project specific NEPA analyses. As if to demonstrate the need for a fact-specific evaluation, BLM screens up to 1,080,000 acres of future coal leasing, yet disclaims the "accuracy, reliability, and completeness" of the screen maps F-2 through F-48. Coal Screen 2's Criterion 9 and Coal Screen 3, as provided, are perfunctory and will not provide a reasonable analysis of foreseeable effects. A direct study through the coal lease application is, and continues to be, a more technically accurate framework to evaluate Coal Screen 3 and portions of Coal Screen 2. BLM cannot proceed with the North Dakota RMP Proposal until this evaluation has been conducted.

ii. Alternatives B and B.1 Will Adversely Affect the Human Environment.

Contrary to BLM's statements in the North Dakota RMP Proposal, Alternatives B and B.1 will likely lead to an increase in GHG emissions in North Dakota by requiring the development of less efficient State and private coal resources. This will frustrate the North Dakota PSC's interest in efficient mining, limited environmental disturbance, and contemporaneous reclamation.

Increased disturbance and environmental impacts. The added complexity to mining from encumbered federal coal leasing under Alternatives B and B.1 will **increase** environmental impacts as companies bypass federal coal reserves in their mining areas. Mining operations that can operate forward in a logical mining unit with fewer encumbrances are more easily managed for reclamation and results in reduced surface disturbance, coal haul distances, redundant soil and subsoil transportation, linear feet of highwall, and promote contemporaneous reclamation.

Due to the unique "checkerboard" of subsurface federal coal within the State, the avoidance of federal coal leasing prevents efficient use of mining acreage and slows the reclamation, reseeding, and restoration for landowners and wildlife. If total coal production (federal plus non-federal) is the same under all Alternatives (which BLM claims), a more fractured mining operation due to federal coal avoidance will actually increase the cumulative air concentrations of pollutants in North Dakota. Associated impacts from the additional surface disturbance and coal haul distances will have air quality impacts including fugitive dust, increased diesel usage, and increased GHG emissions.

The North Dakota PSC has already observed increased surface disturbance and slowed reclamation from the U.S. Department of Interior's delays in mine plan approval for leased federal coal at the BNI Center Mine, the Coyote Creek Mine, the Coteau Properties Company's Freedom Mine and the Falkirk Mine. Although the mines obtained federal leases and the areas were incorporated into the State-approved mining permit, the U.S. Department of Interior has taken over a decade in some instances to provide mine plan approval to allow commencement of mining. There are currently several tracts that have remained in mine plan abeyance with no clear indication that approval will ever be granted.

For example, BLM took over 10 years to issue BNI Coal a federal coal lease for the NW¼ of Section 20, T142N, R84W, Oliver County in Permit BNCR-9702 which resulted in a cessation of mining on private land in the W½ of Section 21. The North Dakota PSC required that BNI develop a reclamation contingency plan in case authorization to mine federal coal is never granted by the U.S. Department of Interior. Approximately 70 acres of reclaimed agricultural land in Section 21 will need to be re-disturbed to achieve a suitable post-mine topography if mining is not authorized and reclamation is being delayed on approximately 320 acres because of the U.S. Department of Interior's mine plan approval delay. This has resulted in a need for BNI to construct 3 sediment ponds, diversions, a dragline erection site, access corridors, overburden and soil stockpiles on the private land overlying federal coal in the NW1/4 of Section 20. Furthermore, overburden overlying federal coal in Section 20 may need to be used to fill the cessation pit in Section 21 to eliminate the highwall adjacent federal coal. Not leasing federal coal in the NW¼ of Section 20 is providing no environmental benefit and has resulted in real increased surface disturbance and GHG emissions in North Dakota.

Delayed federal action for approval to mine federal coal in the SW1/4 of Section 24, T143N, R89W at the Coyote Creek Mine in Mercer County has also delayed reclamation on adjacent lands and created a mine-wide subsoil deficit. To reconcile the delayed federal action, additional surface disturbance will be required on private land overlying federal coal to salvage subsoil quality overburden, and an island of private coal located west of the federal coal tract will become stranded and unlikely to be mined if the federal SW¼ of Section 24.

Social and Economic Impacts. The North Dakota RMP Proposal applies inconsistent logic in its Social and Economic analysis. North Dakota RMP EIS Volume 1 at 3-226. In its analysis, the North Dakota RMP Proposal indicates that closing 90.5 percent of the acreage to coal leasing, compared to the "No Action" Alternative, will reduce potential impacts on general and sensitive populations. However, it assumes that coal production and economic impacts will remain the same under Alternatives B and B.1. *Id.* at 3-18. The North Dakota RMP Proposal indicates that leased federal coal acreage would be reduced, but total coal production is not expected to vary as non-federal coal production would increase to replace federal coal. *Id.* at 3-223. The increased social, economic, and environmental costs of mining around the unleased federal coal have not been analyzed in the North Dakota RMP Proposal, and it is unclear how potential adverse impacts on populations with environmental concerns would result in the largest reduction of potential adverse impacts on populations with environmental justice concerns if adjacent non-federal lands are mined to replace federal coal.

iii. BLM's North Dakota RMP Proposal Conflicts with FLPMA's and the MLA's Statutory Requirements.

Mineral Leasing Act. The MLA sets forth a framework to award leases at the request of a qualified applicant or on its own motion and requires BLM to conduct a comprehensive evaluation that achieves "the maximum economic recovery of the coal. 30 U.S.C. 201(3)(C). To further this goal, BLM, "upon determining that maximum economic recovery of the coal deposit or deposits is served thereby, may approve the consolidation of coal leases into a logical mining unit." 30 U.S.C. 202a. A logical mining unit is an area of land in which the coal resources can be developed in an efficient, economical, and orderly manner as a unit with due regard to conservation of coal reserves and other resources. *Id.*

Of the four Alternatives considered in the 1987 EIS accompanying the 1988 North Dakota RMP, the preferred Alternative was based upon balanced multiple use and intended to maximize production of mineral resources and opportunities for recreation, and consolidation of surface lands into a manageable pattern. Alternative C – 1987 RMP EIS at pg. 17. BLM's proposal to restrict coal leasing outside of existing mining permit area (Alternative B.1), or within 4 miles of an existing permit area (Alternative B), does not comply with the MLA requirement of encouraging the maximum economic recovery of coal within a logical mining unit. BLM's North Dakota RMP Proposal will result in stranded federal and private coal resources as operators alter efficient mining practices to accommodate federal requirements, adversely impairing previously designated logical mining units.

The PSC may approve surface disturbance over federal subsurface coal. The North Dakota RMP Proposal fails to consider that surface disturbance may still occur over subsurface federal coal interests. The Cooperative Agreement between North Dakota and U.S. Department of the Interior states that:

> 7. The Commission may approve and issue permits, permit renewals, and permit revisions for surface disturbances associated with surface coal mining and reclamation operations, and disturbance of the surface may commence without need for an approved mining plan on lands where:
>
> (d) The surface estate is non-Federal and non-Indian;
>
> (b) The mineral estate is Federal and is unleased;
>
> (c) The Commission consults with the Bureau of Land Management through OSM in order to insure that actions are not taken which would substantially and adversely affect the Federal mineral estate; and
>
> (d) The proposed surface disturbances are planned to support surface coal mining and reclamation operations on adjacent non-Federal lands and this is specified in the permit, permit renewal, or permit revision.

30 CFR §934.30. The privately owned surface areas above federal subsurface coal are typically disturbed by mining activities. These areas are used to support mining and are used as soil and overburden stockpile sites, sediment ponds and haul road corridors. Therefore, based on the Cooperative Agreement to which BLM is a party, BLM cannot close federal subsurface coal leasing nor prevent surface disturbance on privately owned land that is overlying federal coal.

iv. BLM's North Dakota RMP Proposal Promotes Conservation and Other Non-Codified Uses Over FLPMA's Multiple Use Mandates.

When revising the land use plans, the action alternatives should respond to a problem or opportunity described in the purpose and need statement and advised by the scoping. The needs highlighted in BLM's North Dakota RMP Proposal for Alterntaive B are to: (1) provide opportunities for mineral and energy development, (2) contribute to conservation and recovery of threatened and endangered special species status, (3) provide recreation opportunities and improved access to BLM land, and (4) manage for other social and scientific values for conservation purposes. North Dakota RMP Proposal EIS, Volume 1 at 1-2-1-3. However, FLPMA's "principal or major uses" do not allow elevation of "social and scientific values" for conservation at the planning stage over "mineral exploration and production." *See* 30 U.S.C. § 1702(l) ("The term "principal or major uses" includes, *and is limited to*, domestic livestock grazing, fish and wildlife development and utilization, mineral exploration and production, rights-of-way, outdoor recreation, and timber production) (emphasis added)).

BLM's North Dakota RMP Proposal states that these "needs" provide opportunities for mineral and energy development, contribute to conservation and recovery of threatened and endangered species and special status species, provide recreation opportunities and access to BLM-administered lands, and manage for other social and scientific values through conservation. However, "conservation" is not a principal use under FLPMA. As such, these needs are also inconsistent with FLPMA's multiple use mandate and do not provide a valid or reasoned justification for BLM to substantially depart from the existing 1988 North Dakota RMP for coal resources.

Notably, BLM's preferred Alternative B effectively closes 98.7 percent of North Dakota's federal coal to leasing under Coal Screen 3. This leaves only approximately 57,019 federal acres available for leasing.[3] Alternative B.1 further restricts federal coal leasing to all areas outside of the current surface coal mining permit boundary, which is 1.5% of federal coal. With 31% of the federal coal in existing coal permit areas already mined, Alternative B.1 leaves only approximately 16,400[4] acres available for mining. This, on its face, is contrary to FLPMA's directive to promote mineral development.

In reviewing the action alternatives as they relate to coal, Alternatives B and B.1 do not reflect FLPMA's multiple use mandate. Alternatives B and B.1 amount to a near-prohibition of federal subsurface coal leasing in the decision area in a long-term RMP. Accordingly, the North Dakota PSC strongly is opposed to BLM's North Dakota RMP Proposal Alternatives B and B.1.

v. BLM's North Dakota RMP Proposal Will Adversely Impair Private Coal Interests and Split Estate Ownership in North Dakota.

Alternatives B and B.1 will negatively impact privately owned coal adjacent to federal tracts and create additional waste and GHG emissions. Under BLM's North Dakota RMP Proposal, State and privately owned coal adjacent to closed federal coal will be stranded, creating significant waste and inefficiencies. For example, where mine plan approval has not been granted, BLM typically requires a 20-foot buffer of coal between private and federal subsurface coal. The average coal seam thickness in North Dakota is approximately nine feet thick with a density of 80.3 lbs/ft^3. If a mine is mining private coal along one side of federal that is one-quarter section in size, approximately 19,080 tons of privately owned coal will be left in place. This is not an efficient development of mineral resources. If the federal coal tract encompasses the north half of a section and privately owned coal is mined around all sides of the federal coal, approximately 153,000 tons of privately owned coal will be left in place. Mining around federal coal increases surface disturbance and financially impacts private mineral owners because it is not economically feasible to go back and mine stranded tracts of coal.

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[3] Based on the PSC's calculation (*See* Attachments EE and FF hereto)

[4] Based on the PSC's calculation (*See* Attachment GG hereto)

Further, the North Dakota RMP Proposal Alternatives B and C state that State and private coal development will offset closed federal coal during the RMP's planning period of 20 years. The development of less efficient State and private coal resources will result in increased and less efficient development of State and private coal resources, ultimately resulting in greater GHG emissions. The North Dakota RMP Proposal has not provided an analysis of the environmental and economic impacts for the closure of federal coal and the increase in State and private coal mining. Therefore, the EIS must be revised to address the environmental and social cost of not leasing federal coal in a logical mine area.

As such, the North Dakota RMP Proposal fails to acknowledge adverse effects on State or private held interests on tracts of land where the federal government does not own the entirety of the coal interest. Appendix K of the North Dakota RMP Proposal, Split Estate Lands, discusses only situations where coal rights are separated from surface ownership and does not address instances in which the federal government owns only a percentage of the coal rights. Within the three major coal producing counties (McLean, Mercer, and Oliver), approximately 22,255 acres of coal rights are only partially owned by BLM. *See* Attachment HH hereto. The social and economic costs, in addition to possible takings of State and private interests, must be addressed in the North Dakota RMP Proposal before BLM can proceed with any final RMP.

Finally, Alternatives B and B.1 attempt to protect resources that have not been characterized in the North Dakota RMP Proposal. The North Dakota RMP Proposal has categorically classified all privately owned land overlying federal coal as a potentially high-value conservation resource without site-specific information. BLM authorities are clear in their directives that coal availability for leasing is to be based on protecting specific, high-value conservation value without an adequate assessment of the validity of that assertion. The North Dakota RMP Proposal does not properly describe or characterize the baseline conditions of the privately owned lands above federal coal to provide a scientific and analytical basis for evaluating the potential impacts of the Alternatives. The Affected Environmental and Environmental Consequences evaluation does not include an analysis or assessment of the private estate overlying federal coal. If an activity or action is not addressed, no impact can be expected or realized. Without further evaluation, it is in violation of FLPMA's multiple use mandate to elevate conservation resource protections over mineral development in the private and split estates overlying federal coal.

vi. The North Dakota RMP Proposal Does Not Consider Cumulative Indirect Impacts to Electric and Natural Customer Rates.

The North Dakota PSC is responsible for the rate regulation for investor-owned utilities. Future restrictions on federal coal and gas leasing will have cost impacts through coal and natural gas electric generation and gas supply.

Load and supply constraints and increasing reliance and natural gas generation has led to scarcity at key times during winter storms such as Uri (2021) and Elliot (2022). These events drive prices high and strain supply to the point that utilities could no longer afford to run the natural gas generators and expose customers to less reliable generation sources in the times of greatest need. In the months following these types of events, the North Dakota PSC saw significant fluctuations in the supply of natural gas and spot pricing. The significant price fluctuations resulted in substantial costs to natural gas heating and electric service that affected billing rates, in some cases, for years. The North Dakota RMP Proposal is deficient in that it does not address the increased costs associated with limiting federal leasing of coal and natural gas that is passed on to consumers, which will disproportionately impact low-income, rural, and disadvantaged communities and citizens subject to fixed incomes.

vii. Existing Information and Maps Relied Upon by BLM Must be Updated.

The boundaries of existing surface coal mining permits in North Dakota that are provided with the North Dakota RMP Proposal are not accurate and the North Dakota RMP Proposal has excluded mines that are in reclamation even though there are remaining coal resources. There are also additional revisions that are likely to be granted approval, but are outstanding due to the Applicant Violator System, an automated information system owned and operated by the Office of Surface Mining Reclamation and Enforcement being offline and unavailable. Revision 42 to NAFK-8405 proposes to add 3,359.7 acres to the permit and Revision No. 8 to BNCR-1101 proposes to add 2,661.04 acres to the permit. The information and maps included in the North Dakota RMP Proposal should be updated to provide accurate and up-to-date permit boundary information.

D. North Dakota Department of Water Resources Concerns with the North Dakota RMP Proposal.

The North Dakota Department of Water Resources ("North Dakota DWR") was created in 2021 by the North Dakota Legislature. The North Dakota DWR was previously the Office of the State Engineer, established in 1905, and the State Water Commission, established in 1937. These entities were created for the specific purpose of fostering and promoting water resources development throughout the State.

The North Dakota DWR has the authority to investigate, plan, construct, and develop water-related projects, and it serves as a mechanism to financially support those efforts throughout North Dakota. The North Dakota DWR sustainably manages and develops North Dakota's water resources for the health, safety, and prosperity of North Dakota's citizens, businesses, agriculture, energy, industry, recreation, and natural resources.

BLM's North Dakota RMP Proposal Alternative B's stated purpose to appropriate waters for the beneficial use of conservation is in violation of North Dakota's constitutional water appropriation requirements which do not recognize conservation as a beneficial use. *See* Section II(H), *supra*. As such, BLM must adopt Alternative A, or the North Dakota RMP Proposal must be substantially reworked to be in accordance with State law.

While Alternative A is preferred, the North Dakota DWR is attaching a spreadsheet as Attachment II to these comments noting the minimum necessary language changes in the North Dakota RMP Proposal to avoid infringing on North Dakota's authority over State water resources. These changes are focused on reflecting North Dakota's primacy over State water resources to resolve conflicts with North Dakota's sovereign authority over those resources in the current North Dakota RMP Proposal.

Finally, the North Dakota DWR also has significant concerns that BLM has not considered the impacts of the North Dakota RMP Proposal on North Dakota's existing water delivery projects in development in the State. Large-scale regional water delivery projects require extensive right-of-way grants for the pipelines that will affect water delivery, and the current surface occupancy stipulations in the North Dakota RMP Proposal will likely greatly impair North Dakota's ability to obtain these rights-of-way.

These water delivery projects include: the Western Area Water Supply Project, the Southwest Pipeline Project (which includes $122 million in federal funding to date), the Red River Valley water supply project, and the Northwest Area Water Supply Project (which includes $176 million in federal funding to date). BLM's proposed surface restrictions in the North Dakota RMP Proposal will significantly impede and restrict North Dakota's ability to develop these projects, which the U.S. Bureau of Reclamation and other federal partners have already invested significant federal funding to advance. The project area maps for these water delivery projects are attached as Attachments JJ, KK, and LL and show the potential areas impacted by BLM's North Dakota RMP Proposal.[5] The North Dakota RMP Proposal must therefore be revised to specifically recognize these projects, exclude them from surface occupancy stipulation barriers, and provide an avenue for the water delivery projects to move forward. Without specific consideration of these water delivery projects, there is a significant risk that water supplies in the State will be jeopardized to the harm of the public and future federal projects.

IV. Conclusion.

For the reasons set forth in this comment letter, BLM must adopt "Alternative A" in the North Dakota RMP Proposal due to the significant legal and technical issues associated with Alternatives B and C.

Sincerely,

DREW H. WRIGLEY
ATTORNEY GENERAL
STATE OF NORTH DAKOTA

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[5] The map area for the Red River Valley Project is available at http://www.rrvwsp.com/about/route/ and is incorporated into these comments by reference.

From: Arik Spencer
To: Beehler, Jace
Subject: RE: Touchbase
Date: Wednesday, December 27, 2023 11:47:23 AM
Attachments: image003.png

Hi Jace,

I hope you had a merry Christmas also, and I would love to connect next week. I'm pretty open the afternoons of the 3rd to 5th, so let me know what works for you.

Arik

Arik Spencer
CEO, President | Greater North Dakota Chamber
PO Box 2639, Bismarck, ND 58502
ndchamber.com | arik@ndchamber.com | 701.222.0929

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Tuesday, December 26, 2023 9:31 PM
To: Arik Spencer <arik@ndchamber.com>
Subject: Touchbase

Hi Arik,

I hope that you had a Merry Christmas and are preparing for a great New Year! I wanted to reach out to see if you wanted to touch base maybe next week? As we head into the new year, our strategy reviews, SOTS and budgeting, I want to ensure we are in sync with you and your members.

Thanks,
Jace

Jace Beehler
Chief of Staff
Office of the Governor
701.328.2201 • 701.610.9431(m) • jabeehler@nd.gov • www.nd.gov

From: Christopher Rager
To: Reiten, John R.; Beehler, Jace
Subject: RE: API Follow Up
Date: Monday, June 17, 2024 3:08:02 PM
Attachments: image001.png

Thanks John. That works.

Best,

Chris

From: Reiten, John R. <jreiten@nd.gov>
Sent: Monday, June 17, 2024 4:05 PM
To: Christopher Rager <RagerC@api.org>; Beehler, Jace <jabeehler@nd.gov>
Subject: RE: API Follow Up

Yes- Happy to!

How does Wednesday at 10 am CST work for you?

John

From: Christopher Rager <RagerC@api.org>
Sent: Monday, June 17, 2024 8:03 AM
To: Beehler, Jace <jabeehler@nd.gov>
Cc: Reiten, John R. <jreiten@nd.gov>
Subject: RE: API Follow Up

Jace,

Good morning. No problem at all. Appreciate your time on this.

John,

Good to meet you via email. Would you have any availability this week to discuss our September Summit?

Best,

Chris

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Monday, June 17, 2024 1:47 AM
To: Christopher Rager <RagerC@api.org>
Cc: Reiten, John R. <jreiten@nd.gov>
Subject: Re: API Follow Up

My apologies for the delay.

Can I have my colleague John Reiten get in touch with you to learn more about the Summit and the potential role the Governor would play?

Thank you,
Jace

From: Christopher Rager <RagerC@api.org>
Sent: Friday, June 14, 2024 7:40 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: FW: API Follow Up

Jace,

Good morning – Happy Friday. Wanted to see if you had a chance to review my below note?

Have a great weekend!!

Chris

From: Christopher Rager
Sent: Monday, June 10, 2024 10:12 AM
To: jabeehler@nd.gov
Subject: API Follow Up

Jace,

Good morning. Great seeing you last week at RGA in New Orleans. Per our conversation, wanted to see if you have some time this week to discuss Governor Burgum's possible participation in our September 25th – 26th State Government Relations Summit?

Best,

Chris

Christopher L. Rager
Director, State Government Relations
American Petroleum Institute
o: 202.682.8389
m: 571-328-6791

www.api.org

signature_1982813188

From: Christopher Rager
To: Beehler, Jace
Cc: Reiten, John R.
Subject: RE: API Follow Up
Date: Monday, June 17, 2024 8:03:24 AM
Attachments: image001.png

Jace,

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Cc: Reiten, John R. <jreiten@nd.gov>
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www.api.org

signature_1982813188

From: Christopher Rager
To: Beehler, Jace
Subject: FW: API Follow Up
Date: Friday, June 14, 2024 7:40:25 AM
Attachments: image001.png

Jace,

Good morning – Happy Friday. Wanted to see if you had a chance to review my below note?

Have a great weekend!!

Chris

From: Christopher Rager
Sent: Monday, June 10, 2024 10:12 AM
To: jabeehler@nd.gov
Subject: API Follow Up

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Best,

Chris

Christopher L. Rager
Director, State Government Relations
American Petroleum Institute
o: 202.682.8389
m: 571-328-6791

www.api.org

signature_1982813188

From: Helms, Lynn D.
To: Sisk, Susan M.; Bloms, Renae R.; Kringstad, Justin; Ron Ness; Beehler, Jace; Haase, Reice; Teigen, Joshua L.
Cc: Ziesch, Michael D.; Danso, Bridget Y.
Subject: March 2024 Oil and Gas Update
Date: Thursday, March 14, 2024 1:41:42 PM
Attachments: image005.png
image007.png

Oil Production

December 39,520,924 barrels = 1,274,869 barrels/day (final) **RF+16%**
NM 56,180,976 barrels = 1,812,290 +1.4%
January 34,177,679 barrels = 1,102,506 barrels/day **-13.5%** **RF+.2%**
1,519,037 all-time high Nov 2019
1,073,615 barrels/day = 97% from Bakken and Three Forks
28,891 barrels/day = 3% from legacy pools
Revenue Forecast **1,100,000 barrels/day**

Crude Price ($/Bbl)	**NDLightSweet**	**WTI**	**ND Market**	
December	61.46	72.12	64.99	**RF -7%**
January	63.64	73.86	66.40	**RF -5%**
Today	69.75	79.72	74.74 est	**RF +7%**
All-time high(06/2008)	125.62	134.02	126.75	
Revenue Forecast			**70.00**	

Gas Production and Capture

December 109,389,872 MCF = 3,528,706 MCF/day
95% Capture 104,008,399 MCF = 3,355,110 MCF/day
January 93,009,641 MCF = 3,000,311 MCF/day **-15%**
93% Capture 86,943,905 MCF = 2,804,642 MCF/day
3,582,821 MCF/day all-time high production Dec 2023
3,355,110 MCF/day all-time high capture Dec 2023

Rig Count	
December	36
January	38
February	38
Today	38 (all-time high was 218 on 5/29/2012)
Federal surface	0
New Mexico	106

Wells Permitted

December	57
January	78
February	63 (all-time high was 370 in 10/2012)

Completed

December	80
January	102 (preliminary)
February	92 (preliminary)

Waiting on Completion

December	331
January	284

Producing

December	18,769
January	18,691 (preliminary)(**all-time high 18,769 Dec 2023**)

16,500 wells or 88% are now unconventional Bakken – Three Forks
2,191 wells or 12% produce from legacy-conventional

Inactive

December	1,469
January	1,490

IIJA Initial Grant	**Wells PA**	**Sites Reclaimed**
January	1	0
February	4	0
March	1	0
April	8	0
May	17	0
June	12	1
July	15	5
August	15	13
September	0	14
October	0	10
November	0	0
December	0	1
January	0	0
February	0	0
Total	73	44

Weekly updates are available at Initial Grant Information - Plugging and Reclamation | Department of Mineral Resources, North Dakota

Fort Berthold Reservation activity
7 drilling rigs (2 on trust lands and 5 on fee lands)
117,893 barrels of oil per day (68,994 from trust lands & 48,899 from fee lands)
2,661 active wells (2,009 on trust lands & 652 on fee lands)
24 wells waiting on completion
135 approved drilling permits (125 on trust lands & 10 on fee lands)
2,019 potential future wells (1,411 on trust lands & 608 on fee lands)

Comments:
The drilling rig count remains low due to demand, mergers, and acquisitions but is expected to return to the mid-forties with a gradual increase expected over the next 2 years.

There are 13 frac crews currently active.

Saudi Arabia and Russia announced continued oil production cuts through second quarter of the year. Middle East conflict, Russia sanctions, China economic activity, potential recessions, and shifting crude oil supply chains continue to create significant price volatility.

Stock price graphs

Crude oil transportation capacity including rail deliveries to coastal refineries is adequate, but could be disrupted due to:
US Appeals Court for the ninth circuit upholding of a lower court ruling protecting the Swinomish Indian Tribal Community's right to sue to enforce an agreement that restricts the number of trains that can cross its reservation in northwest Washington state.
DAPL Civil Action No. 16-1534 continues, but the courts have now ruled that

DAPL can continue normal operations until the USACOE EIS is completed. **Corrected Draft EIS was released 9/11/23. North Dakota submitted comments 12/13/23** Comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

Drilling - activity is expected to increase slightly and operators continue to maintain a permit inventory of approximately 12 months.

Seismic - 0 active, 1 recording, 0 NDIC reclamation projects, 0 remediating, 1 permitted, and 4 suspended surveys, 0 pending.

US natural gas storage is 37% above the five-year average. US and world crude oil inventories are about average and the US strategic petroleum reserve remains at the lowest levels since 1983.
The price of natural gas delivered to Northern Border at Watford City at $1.13/MCF continues at 20-30 year lows (lowest since June 1996). There is continued oversupply in the Midwest US and the Biden Administration's decision to suspend LNG export permitting has created a huge nationwide oversupply. Current oil to gas price ratio is 66:1. The state-wide gas flared volume from December to January increased 22 MMCFD to 196 MMCF per day, the statewide gas capture decreased slightly to 93% while Bakken gas capture was unchanged at 95%. The historical high flared percent was 36% in 09/2011.

Gas capture details are as follows:

Statewide	93%
Statewide Bakken	94%
Non-FBIR Bakken	94%
FBIR Bakken	95%
Trust FBIR Bakken	95%
Fee FBIR	93%
Fertile Valley	75%
Burg	76%
Hanks	65%
Bar Butte	57%
Zahl	78%
Green Lake	68%
Little Muddy	68%
Round Prairie	41%
Painted Woods	77%
Ft. Buford	59%
Lake Trenton	35%
Sixmile	10%
Buford	43%
Briar Creek	85%
Assiniboine	72%
Lone Butte	47%
Ranch Creek	72%
Twin Buttes	60%
Charlson	82%

The Commission has established the following gas capture goals:
74% October 1, 2014 through December 31, 2014
77% January 1, 2015 through March 31, 2016
80% April 1, 2016 through October 31, 2016
85% November 1, 2016 through October 31, 2018
88% November 1, 2018 through October 31, 2020
91% beginning November 1, 2020

BLM On 1/27/21 President Biden issued an executive order that mandates a "pause" on new oil and gas leasing on federal lands, onshore and offshore, "to the extent consistent with applicable law," while a comprehensive review of oil and gas permitting and leasing is conducted by the Interior Department. There is no time limit on the review, so the moratorium on new leasing is indefinite. The order does not restrict energy activities on lands the government holds in trust for Native American tribes.
On 7/7/21 North Dakota sued the Department of Interior (DOI), Secretary of Interior, Bureau of Land Management (BLM), Director of the BLM, and Director

of the Montana-Dakotas BLM in US District Court for the District of North Dakota. The lawsuit requested the court compel the Federal Defendants to hold quarterly lease sales, prohibit the Federal Defendants from cancelling quarterly lease sales, enjoin the Secretary from implementing a moratorium on federal lease sales, declare that Federal Defendants are in violation of MLA, FLPMA, NEPA, and APA, and grant other relief sought and as the court deems proper to remedy the violations.

Oral arguments were presented 1/12/22 in Bismarck. On 01/14/2022 Judge Traynor denied North Dakota's motion without prejudice. In the Order on Mandamus, the Court noted that "a fully developed factual record is necessary to resolve the instant dispute." The Court also held that because Federal Defendants had given the Court "assurances at the hearing the process to start Federal oil and gas leasing sales in North Dakota was imminent" mandamus relief was "unnecessary." However, the Court noted that "if the Defendants do not hold to their word and cancel any planned future sale, North Dakota may bring this action for review of the specifically cancelled sales once this Court has the benefit of a complete record.

North Dakota filed a motion for preliminary injunction on 1/6/23, a hearing on the motions was held 2/21/23 in Minot with final briefing documents filed 3/14/23. On 3/27/23 U.S. District Judge Daniel Traynor in Bismarck ordered the Bureau of Land Management (BLM) to resume conducting quarterly oil and gas lease sales in North Dakota that had been illegally cancelled by BLM. The next status hearing is 5/29/24. The transcript of the 2/9/24 status hearing is available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

On 6/28/22 DAKOTA RESOURCE COUNCIL, CENTER FOR BIOLOGICAL DIVERSITY, CITIZENS FOR A HEALTHY COMMUNITY, LIVING RIVERS & COLORADO RIVERKEEPER, MONTANA ENVIRONMENTAL INFORMATION CENTER, RIO GRANDE RIVERKEEPER, SIERRA CLUB, WATERKEEPER ALLIANCE, WESTERN WATERSHEDS PROJECT, and WILDEARTH GUARDIANS sued DOI to challenge leasing decisions on 173 parcels including those in North Dakota. On 8/09/2022 the U.S. District Court in DC granted North Dakota's Motion to Intervene in the NGO's challenge to the legality of BLM's quarterly lease sales in Dakota Resource Council et al. v. U.S. Department of the Interior et al., 1:22-cv-01853-CRC.

On 9/6/22 the BLM and a group of NGOs filed a proposed settlement in the District Court of Montana in which BLM agrees to not issue drilling permits on 2019 and 2020 federal leases in North Dakota, Montana and South Dakota pending the completion of revised NEPA analyses that must take into account factors such as the social cost of carbon. This is a revival of the "sue and settle" litigation strategy whereby the Biden Administration settles litigation brought by NGOs in a manner that furthers the Administration's policy goals. The case was filed on 1/12/2021 by the same group of NGOs involved in North Dakota's leasing cases. The proposed settlement would cover 5 lease sales that authorized the sale of 113 leases encompassing 58,617 acres in North Dakota, Montana, and South Dakota. 55 North Dakota Parcels, 9,564.347 Federal Acres in North Dakota (leases Expire in 2029 and 2030), if permitting is delayed 7-8 years 130 wells will not be drilled, 58,329,000 barrels of oil will not be produced, GPT+OET+SalesTax+IncomeTax+NDRoyaltyShare+NDTLRoyalties @ $50/barrel = $8,006,217 per month = $960,746,074 over ten years.

BLM has posted for comment NEPA Number: DOI-BLM-HQ-3100-2023-0001-EA, Project Name: Supplemental Environmental Assessment Analysis for Greenhouse Gas Emissions Related to Oil and Gas Leasing in Seven States from February 2015 to December 2020, Project Type: Environmental Assessment, Project Status: In Progress - Public Review and Comment Period, Lead Office: HQ-310. Bureau of Land Management has released an updated environmental assessment for public comment. The additional review analyzes greenhouse gas emissions that may result from reasonably foreseeable development of 3,600 oil and gas leases that were sold in 74 lease sales between February 2015 and December 2020 that were the subject of litigation. The leases span approximately 3,433,615 acres in Colorado, Montana, New Mexico, Utah, Wyoming, North Dakota, and South Dakota. The environmental analysis looks at the development activity that would result in greenhouse gas emissions due to well development and production operations, as well as the end-use of the petroleum products produced from oil and gas leases. The supplemental analysis is in response to numerous court rulings and settlements. It incorporates new information and ensures consistency with recent court decisions, Executive and Secretarial Orders, and Department of the Interior policy. This analysis of greenhouse gas emissions supplements the greenhouse gas analysis provided in the previous National Environmental Policy Act (NEPA) documents supporting the 74 lease sales. The previous environmental assessments or determinations of NEPA adequacy, decision records, and findings of no significant impacts for the 74 lease sales are listed on BLM's State Oil and Gas Lease Sale website, which contains detailed information for the lease sales in each field office. Decisions related to the affected lease sales will be made separately and will include additional analysis of impacts to other resources, as appropriate. NDIC comments are available by request at [Contact | Department of Mineral Resources, North Dakota (nd.gov)](https://www.dmr.nd.gov).

BLM published a new final rule 43 CFR Parts 3100, 3160 and 3170 to update and replace its regulations on venting and flaring of natural gas effective 1/17/16. The final rule can be viewed online at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/methane-and-waste-prevention-rule. North Dakota, Wyoming, Montana, Western Energy Alliance, and IPAA filed for a preliminary injunction to prevent the rule going into effect until the case is settled. A hearing in Casper, Wyoming was held 1/6/17. On 1/16/17 the court denied all of the petitioners' motions for preliminary injunctions. **On 2/3/17 the US House of Representatives voted 221-191 to approve a Congressional Review Act resolution against the rule.** On 3/28/17 President Trump issued an executive order which in part directs "The Secretary of the Interior shall review the following final rules, and any rules and guidance issued pursuant to them, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules". This rule is included in the list as item (iv). North Dakota plans to continue active participation in the litigation of this rule until the BLM takes final action eliminating the rule. **On 5/10/17 the Senate voted 51 to 49 against the CRA, allowing the rule to remain in effect.**

The Bureau of Land Management (BLM) is proposing new regulations very similar to the venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases rules of 2016 that were struck down by the court. The proposed regulations would be codified in the Code of Federal Regulations and would replace the BLM's current requirements governing venting and flaring, which are more than four decades old. NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov)

BLM The Bureau of Land Management on 1/20/23 announced the **North Dakota Draft Resource Management Plan** and its associated draft environmental impact statement are available for public comment for a 90-day period ending April 20, 2023. **The comment period has been extended to end 5/20/23.** The draft resource management plan and draft environmental impact statement address management of approximately 58,500 acres of BLM-administered surface and 4.1 million acres of federal mineral estate in North Dakota for the next 20 to 30 years. Key issues raised during the public scoping period included mineral and energy resources, wildlife, recreation, water resources, air, and climate. In response to Tribal concerns, a "no surface occupancy" lease stipulation within a half mile of the Missouri River, Lake Sakakawea, and Lake Oahe has been added to the alternatives included in the documents. This stipulation is consistent with the Mandan, Hidatsa and Arikara Nation's Tribal Resolution and recognizes the regional importance of the Missouri River as a major supply of public drinking water. NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov)

BLM On 4/3/23 The Bureau of Land Management (BLM) proposed new regulations that, pursuant to the Federal Land Policy and Management Act of 1976 (FLPMA), as amended, and other relevant authorities, would advance the BLM's mission to manage the public lands for multiple use and sustained yield by prioritizing the **health and resilience of ecosystems across those lands.** To ensure that health and resilience, the proposed rule provides that the BLM will protect intact landscapes, restore degraded habitat, and make wise management decisions based on science and data. To support these activities, the proposed rule would apply land health standards to all BLM-managed public lands and uses, clarify that conservation is a "use" within FLPMA's multiple-use framework, and revise existing regulations to better meet FLPMA's requirement that the BLM prioritize designating and protecting Areas of Critical Environmental Concern (ACECs). The proposed rule would add to provide an overarching framework for multiple BLM programs to promote ecosystem resilience on public lands. NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov) North Dakota has responded to a request to become a cooperating agency and has signed a MOU.

BLM On 7/24/23 The Bureau of Land Management (BLM) proposed to revise the BLM's **oil and gas leasing regulations.** Among other things, the proposed rule would reflect provisions of the Inflation Reduction Act pertaining to royalty rates, rentals, and minimum bids, and would update the bonding requirements for leasing, development, production, as well as revise some operating requirements. **North Dakota's requested comment period extension was denied and comments were filed 9/22/2023.** NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

Congress On 08/07/2022 the US Senate and on 08/12/2022 the US House passed HR 5376 which is expected to be signed into law by the president and contains numerous provisions that will negatively impact oil and gas producers and transporters. NDIC is in the process of analyzing the potential impact of Section 10101. CORPORATE ALTERNATIVE MINIMUM TAX, Section 10201 EXCISE TAX ON REPURCHASE OF CORPORATE STOCK, Section 13104 CREDIT FOR CARBON OXIVDE SEQUESTRATION, Section 13502 ADVANCED MANUFACTURING PRODUCTION CREDIT critical minerals, Section 60113 METHANE EMISSIONS REDUCTION PROGRAM, Section 50262 MINERAL LEASING ACT MODERNIZATION, on North Dakota's mineral industries.

CEQ On 7/31/23 the Council on Environmental Quality (CEQ) is proposing this ''Bipartisan Permitting Reform Implementation Rule'' to revise its regulations for implementing the procedural provisions of the **National Environmental Policy Act (NEPA),** including to implement the Fiscal Responsibility Act's amendments to NEPA. CEQ invites comments on the proposed revisions. **North Dakota's comments were filed 9/29/2023.** NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

DPGL On 10/20/23 Dakota Prairie Grasslands announced the start of a 2-3 year process to develop a Travel Management Plan. North Dakota is negotiating a MOU to be a cooperating agency in the process.

EPA On 12/2/23 EPA released its final rule entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions" (2023 Methane Rule). On 12/6/22 The EPA issued a proposal to update, strengthen, and expand the standards proposed on November 15, 2021 which are intended to significantly reduce emissions of greenhouse gases (GHGs) and other harmful air pollutants from the Crude Oil and Natural Gas source category. First, the EPA proposes standards for certain sources that were not addressed in the November 2021 proposal. Second, the EPA proposes revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super emitter response program. Third, the EPA proposes to modify and refine certain elements of the proposed standards in response to information submitted in public comments on the November 2021 proposal. Finally, the EPA proposes details of the timelines and other implementation requirements that apply to states to limit methane pollution from existing designated facilities in the source category under the Clean Air Act (CAA). NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov). North Dakota is part of a coalition of states lead by West Virginia that are challenging the rules.

EPA On 5/23/23 the Environmental Protection Agency (EPA) issued a proposal titled, "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule". NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

EPA On 2/20/24 EPA released its final rule entitled "Waste Emissions Charge for Petroleum and Natural Gas Systems; Extension of Comment Period". In August 2022, the Inflation Reduction Act of 2022 (IRA) was signed into law. Section 60113 of the IRA amended the CAA by adding section 136, "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems." CAA section 136(c) directs the Administrator of EPA to impose and collect a WEC on methane emissions that exceed statutorily specified waste emissions levels from an owner or operator of an "applicable facility." The waste emissions level is a facility-specific amount of methane emissions (metric tons) calculated using segment-specific methane intensity levels defined in CAA section 136(f)(1)-(3) and the amount of natural gas (or oil, in certain circumstances) that the facility sends to sale. The U.S. Environmental Protection Agency (EPA) is proposing a regulation to implement provisions of the Inflation Reduction Act that require the Agency to collect an annual Waste Emissions Charge (WEC) on methane emissions from oil and natural gas facilities that exceed specific levels of emissions and methane intensity specified in the IRA. Details are available at https://www.epa.gov/inflation-reduction-act/waste-emissions-charge. The comment period for the proposed rule published on January 26, 2024, at 89 FR 5318, is extended. Comments must be received on or before March 26, 2024. You may send your comments, identified by Docket ID No. EPA-HQ-OAR-2023-0434, by any of the following methods: • Federal eRulemaking Portal: http:// www.regulations.gov (our preferred method) Follow the online instructions for submitting comments. • Mail: U.S. Environmental Protection Agency, EPA Docket Center, Office of Air and Radiation Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460. • Hand Delivery: EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, VerDate Sep<11>2014 16:27 Feb 16, 2024 Jkt 262001 PO 00000 Frm 00038 Fmt 4702 Sfmt 4702 E:\FR\FM\20FEP1.SGM 20FEP1 ddrumheller on DSK120RN23PROD with PROPOSALS1 12796 Federal Register / Vol. 89, No. 34 / Tuesday, February 20, 2024 / Proposed Rules DC 20004. The Docket Center's hours of operations are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal Holidays). Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to https:// www.regulations.gov/, including any personal information provided. Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2023-0434, at https://www.regulations.gov (our preferred method), or the other methods identified in the ADDRESSES section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e., on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit https://www.epa.gov/dockets/ commenting-epa-dockets.

PHMSA On 5/18/23 PHMSA proposed regulatory amendments that implement congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 to **reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, regulated (Types A, B, C and offshore) gas gathering pipelines, underground natural gas storage facilities, and liquefied natural gas facilities**. Among the proposed amendments for part 192-regulated gas pipelines are strengthened leakage survey and patrolling requirements; performance standards for advanced leak detection programs; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; and clarified requirements for investigating failures. Finally, PHMSA proposes expanded reporting requirements for operators of all gas pipeline facilities within DOT's jurisdiction, including underground natural gas storage facilities and liquefied natural gas facilities. **North Dakota's comments were filed 8/16/2023.** NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

SEC On Sept. 27, the New York Stock Exchange quietly submitted a substantial and financially material proposed change to its rules. The proposal would allow the formation of a new type of company. Natural Asset Companies, or NACs, would purchase the rights to control public and private lands, such as parks, forests and farms. But a NAC wouldn't be able to put the land to economic use. Instead, it would preserve its acquisitions to maximize the value of the land's "ecological services." NACs would register to go public on the NYSE. The money raised would purchase land and effectively lock it away from human impact. Grazing, energy extraction and other economically critical activities would disappear on NAC-protected land. Farmland used to feed the nation and world would go back to natural landscape, erasing human activity. The resulting conversion of investor money into unusable wildlands has the potential to be one of the most significant misallocations of capital in history. Normally, corporations are formed for investors to make money. But since NACs are clearly noneconomic, a rule is required to allow their formation. The land placed in a NAC, a private entity, must support only "replenishable" activities. Since no economic activity can occur, the property is assigned an arbitrary value and traded on that basis. In any other situation, this proposal would be identified as sanctioning fraud. Why would anyone invest in a company that can't make money? Initial buyers would likely be "impact investors," committed to sacrificing returns to advance the climate agenda. But it seems clear the goal is to sell NACs to endowments, sovereign wealth funds, pension funds and other investors demanding greater direct and immediate ESG presence in their portfolio. Demand from "values-driven investing" alone could drive up NAC share prices even as the value of the assets they purchase decrease by virtue of the NAC's ownership of them. More disturbing, reducing U.S. mineral extraction could be intriguing to Chinese, Russian or Saudi sovereign wealth funds. Environmental offsets in the form of carbon credits or government transfers for "conservation uses" could also generate ostensible revenues. The supposedly temporary Wind Production Tax Credit is an example of government policy used to benefit dubious investment choices at the behest of well-connected private-equity firms. Both private and public land is eligible for a NAC to purchase. Federal and state governments will surely sell public land to NACs, appeasing environmentalist constituencies under the guise of generating revenue. If NACs market themselves successfully, a significant amount of land will be removed from productive use. In western states like Utah, where the federal government owns 67% of the state, the effect could be devastating. Rural communities in the West, deprived of property tax revenue on vast federal land, pay for public improvements primarily through levies from extracting minerals on state land. The Biden administration's attack on energy has already reduced this essential revenue. The federal government has long fought the purchase of public land by private parties, and this is a dramatic change in policy. **On 1/17/24 SEC withdrew the proposed rule. North Dakota's comments were filed 1/17/24.** ND comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

USFWL On 6/22/23 the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS; collectively, the ''Services''), propose to revise portions of our regulations that implement the **Endangered Species Act** of 1973, as amended (Act). The proposed revisions to the regulations clarify, interpret, and implement portions of the Act concerning the procedures and criteria used for listing, reclassifying, and delisting species on the Lists of Endangered and Threatened Wildlife and Plants and designating critical habitat,the interagency consultation processes, reinstate the general application of the ''blanket rule'' option for protecting newly listed threatened species pursuant to section 4(d) of the Act, with the continued option to promulgate species-specific rules. We are also proposing to extend to federally recognized Tribes the exceptions to prohibitions for threatened species that the regulations currently provide to the employees or agents of the Service and other Federal and State agencies to aid, salvage, or dispose of threatened species. We are also proposing minor changes to clarify or correct the existing regulations for endangered and threatened species; these proposed minor changes would not alter the substance or scope of the regulations. We also request comments on an additional provision under consideration, but not currently proposed, that would extend to federally recognized Tribes the exceptions to prohibitions for threatened species that the regulations currently provide to employees or agents of the Service, the National Marine Fisheries Service, and State agencies for take associated with conservation-related activities, streamline our process for permitting of rights-of-way across National Wildlife Refuge System lands and other Service administered lands. By aligning Service processes more closely with those of other Department of the Interior (DOI) bureaus, to the extent practicable and consistent with applicable law, we will reduce the amount of time the Service requires to process applications for rights-of-way across Service-managed lands. We originally proposed revisions that included requiring a preapplication meeting and use of a standard application, allowing electronic submission of applications, and providing the Service with additional flexibility, as appropriate, to determine the fair market value or fair market rental value of rights-of-way across Service-managed lands. We now further propose new permit terms and conditions and other regulatory changes. **North Dakota signed onto comments filed by Alabama on 8/21/2023.** Comments are available by request at Contact | Department of Mineral

Resources, North Dakota (nd.gov).

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From: Brady Pelton
To: Brady Pelton
Cc: Micaela Rud
Subject: RE: YOU"RE INVITED! - ND Petroleum Council March Board Events
Date: Friday, February 23, 2024 9:37:50 AM
Attachments: image001.png
image002.png
Importance: High

Good morning, and a happy Friday to you!

As we make final preparations for next week's activities, I wanted to be sure to reach out to those I have not heard from yet regarding the North Dakota Petroleum Council's invitation to join its Board of Directors and other honored guests for the Friday, March 1 hockey game at the University of North Dakota. Puck drop is scheduled for 7:07 at the world-class Ralph Engelstad Arena, and we would be honored to have you join us as the Fighting Hawks take on Western Michigan.

If you are able to join us, please RSVP here: NDPC Social & Hockey Night
So we can have an adequate number of tickets, **please RSVP by end of business today if at all possible**.

Thank you for all you do for our state, and we look forward to visiting with you next week in Grand Forks!

Best regards,
Brady

BRADY PELTON
Vice President & General Counsel

North Dakota Petroleum Council

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701.557.7743 – Direct
701.260.2479 – Cell
bpelton@ndoil.org

From: Brady Pelton
Sent: Monday, February 12, 2024 5:15 PM
To: Brady Pelton <bpelton@ndoil.org>
Cc: Micaela Rud <mrud@ndoil.org>
Subject: YOU'RE INVITED! - ND Petroleum Council March Board Events

Importance: High

Good afternoon, North Dakota leaders:

The North Dakota Petroleum Council Board of Directors and guests are eagerly awaiting our February 29-March 1 visit to Grand Forks and the University of North Dakota!

In advance of our two-day visit, we wanted to share the invitation below from the Energy & Environmental Research Center (EERC):

> You are cordially invited to a luncheon at the University of North Dakota (UND) Energy & Environmental Research Center (EERC) on Friday, March 1, 2024, at noon. Attendees include state and local leaders and North Dakota Petroleum Council members.
>
> Following the luncheon, you have an opportunity to tour the EERC or the College of Engineering & Mines (CEM). You can join the EERC for a journey through the EERC's expanding array of projects, deeply meaningful for our state, and the entire region.
>
> - Option 1: At the EERC, the tour will include, but not be limited to, research on Bakken, salt caverns, rare-earth elements, CO_2 capture and storage, development of new materials, and the latest update to our expanding hydrogen program. During the tour, you will hear from our professional research staff who bring a wealth of expertise to these impactful areas. The EERC team is looking forward to answering any questions you may have and the opportunity to connect with leadership from North Dakota and our entire region.
> - Option 2: Dean Brian Tande will lead a tour of the College of Engineering & Mines National Security Corridor and the Collaborative Energy Center. CEM research has grown by more than 40% in the past several years, with over $9M in areas such as energy, rare-earth elements, UAS, and national security.
>
> Please RSVP by February 15, 2024, for both the luncheon and the tour at this link: use this link.

Capping off the events on Friday, NDPC will host a social at the CanadInn’s Playmakers Lounge from 4:30 to 6:00 p.m. and then host guests at the Ralph as UND takes on Western Michigan in some good old North Dakota hockey. Hockey tickets are sponsored by our great friends at AE2S, Construction Engineers, and the UND Alumni Association & Foundation. We have a hockey ticket for you. However, if you have access to other tickets, please use those and find us on the suite level (Suites 201 and 204; Alumni Association suite is 225).

In order to best prepare for meals and other logistics, we ask that you RSVP by

February 15th at each of the links below.

Friday, March 1 - EERC Lunch & Tour Invite
Friday, March 1 - NDPC Social & Hockey Night

Thank you all for your continued support and please contact me with any questions. We look forward to seeing each of you.

Best regards,
Brady

Brady Pelton
Vice President & General Counsel

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From: Helms, Lynn D.
To: Sisk, Susan M.; Bloms, Renae R.; Kringstad, Justin; Ron Ness; Beehler, Jace; Haase, Reice; Teigen, Joshua L.
Cc: Ziesch, Michael D.; Danso, Bridget Y.
Subject: February 2024 Oil and Gas Update
Date: Thursday, February 15, 2024 12:47:16 PM
Attachments: image002.png
image004.png

Oil Production
November 38,367,281 barrels = 1,278,909 barrels/day (final) **RF+16%**
NM 56,180,976 barrels = 1,812,290 +1.4%
December 39,465,191 barrels = 1,273,071 barrels/day **-.5%** **RF+16%**
1,519,037 all-time high Nov 2019
1,241,851 barrels/day = 98% from Bakken and Three Forks
31,219 barrels/day = 2% from legacy pools
Revenue Forecast **1,100,000 barrels/day**

Crude Price($/Bbl)	**NDLightSweet**	**WTI**	**ND Market**	
November	71.61	77.69	72.55	**RF +4%**
December	61.46	71.90	64.99	**RF -7%**
Today	66.50	76.64	71.57	**RF +2%**
All-time high(06/2008)	125.62	134.02	126.75	
Revenue Forecast			**70.00**	

Gas Production and Capture
November 104,075,685 MCF = 3,469,190 MCF/day
95% Capture 98,405,522 MCF = 3,280,184 MCF/day
December 109,264,074 MCF = 3,524,648 MCF/day **+1.6%**
95% Capture 103,880,140 MCF = 3,350,972 MCF/day
3,524,648 MCF/day all-time high production Dec 2023
3,350,972 MCF/day all-time high capture Dec 2023

Rig Count	
November	36
December	36
January	38
Today	37 (all-time high was 218 on 5/29/2012)
Federal surface	0
New Mexico	101

Wells

Permitted	
November	51
December	57
January	78 (all-time high was 370 in 10/2012)

Completed	
November	111
December	80 (preliminary)
January	102 (preliminary)

Waiting on Completion	
November	345
December	331

Producing	
November	18,743
December	18,753 (preliminary)(**NEW all-time high 18,753 Dec 2023**)

16,560 wells or 88% are now unconventional Bakken – Three Forks
2,193 wells or 12% produce from legacy-conventional

Inactive

November	1,847
December	1,469

IIJA Initial Grant	**Wells PA**	**Sites Reclaimed**
January	1	0
February	4	0
March	1	0
April	8	0
May	17	0
June	12	1
July	15	5
August	15	13
September	0	14
October	0	10
November	0	0
December	0	1
January	0	1
Total	73	44

Weekly updates are available at Initial Grant Information - Plugging and Reclamation | Department of Mineral Resources, North Dakota

Fort Berthold Reservation activity
7 drilling rigs (2 on trust lands and 5 on fee lands)
143,665 barrels of oil per day (85,807 from trust lands & 57,858 from fee lands)
2,661 active wells (2,009 on trust lands & 652 on fee lands)
19 wells waiting on completion
138 approved drilling permits (129 on trust lands & 9 on fee lands)
3,891 potential future wells (2,779 on trust lands & 1,112 on fee lands)

Comments:
The drilling rig count remains low due to workforce, mergers, and acquisitions but is expected to return to the mid-forties with a gradual increase expected over the next 2 years.

There are 13 frac crews currently active.

Saudi Arabia and Russia announced continued oil production cuts amounting to 4.7 million bpd until the end of the year. Middle East conflict, Russia sanctions, China economic activity, potential recessions, and shifting crude oil supply chains continue to create significant price volatility.

Stock price graphs

Crude oil transportation capacity including rail deliveries to coastal refineries is adequate, but could be disrupted due to:
US Appeals Court for the ninth circuit upholding of a lower court ruling protecting the Swinomish Indian Tribal Community's right to sue to enforce an agreement that restricts the number of trains that can cross its reservation in northwest Washington state.
DAPL Civil Action No. 16-1534 continues, but the courts have now ruled that DAPL can continue normal operations until the USACOE EIS is completed.
Corrected Draft EIS was released 9/11/23. North Dakota submitted comments 12/13/23 Comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

Drilling - activity is expected to slowly increase with operators expected to maintain a permit inventory of approximately 12 months.

Seismic - 2 active, 1 recording, 0 NDIC reclamation projects, 0 remediating, 0 permitted, and 4 suspended surveys, 0 pending.

US natural gas storage is 11% above the five-year average. US and world crude oil inventories are below average and the US strategic petroleum reserve remains at the lowest level since 1983.

The price of natural gas delivered to Northern Border at Watford City has fallen to $1.17/MCF today (lowest since June 1996). There is continued oversupply in the Midwest US and the Biden Administration's decision to suspend LNG export permitting has created a huge nationwide oversupply. Current oil to gas price ratio is 61:1. The state-wide gas flared volume from November to December decreased 15.3 MMCFD to 174 MMCF per day, the statewide gas capture remained 95% while Bakken gas capture was unchanged at 95%. The historical high flared percent was 36% in 09/2011.

Gas capture details are as follows:

Statewide	95%
Statewide Bakken	95%
Non-FBIR Bakken	95%
FBIR Bakken	97%
Trust FBIR Bakken	97%
Fee FBIR	95%
Fertile Valley	73%
Burg	75%
Hanks	39%
Bar Butte	51%
Zahl	74%
Green Lake	68%
Little Muddy	71%
Round Prairie	33%
Painted Woods	85%
Ft. Buford	74%
Lake Trenton	79%
Sixmile	8%
Buford	6%
Briar Creek	88%
Assiniboine	62%
Lone Butte	30%
Ranch Creek	62%
Twin Buttes	55%
Charlson	89%

The Commission has established the following gas capture goals:
74% October 1, 2014 through December 31, 2014
77% January 1, 2015 through March 31, 2016
80% April 1, 2016 through October 31, 2016
85% November 1, 2016 through October 31, 2018
88% November 1, 2018 through October 31, 2020
91% beginning November 1, 2020

BLM On 1/27/21 President Biden issued an executive order that mandates a "pause" on new oil and gas leasing on federal lands, onshore and offshore, "to the extent consistent with applicable law," while a comprehensive review of oil and gas permitting and leasing is conducted by the Interior Department. There is no time limit on the review, so the moratorium on new leasing is indefinite. The order does not restrict energy activities on lands the government holds in trust for Native American tribes.
On 7/7/21 North Dakota sued the Department of Interior (DOI), Secretary of Interior, Bureau of Land Management (BLM), Director of the BLM, and Director of the Montana-Dakotas BLM in US District Court for the District of North Dakota. The lawsuit requested the court compel the Federal Defendants to hold quarterly lease sales, prohibit the Federal Defendants from cancelling quarterly lease sales, enjoin the Secretary from implementing a moratorium on federal lease sales, declare that Federal Defendants are in violation of MLA, FLPMA, NEPA, and APA, and grant other relief sought and as the court deems proper to remedy the violations.
Oral arguments were presented 1/12/22 in Bismarck. On 01/14/2022 Judge Traynor denied North Dakota's motion without prejudice. In the Order on Mandamus, the Court noted that "a fully developed factual record is necessary to resolve the instant dispute." The Court also held that because Federal Defendants had given the Court "assurances at the hearing the process to start Federal oil and gas leasing sales in North Dakota was imminent" mandamus relief was "unnecessary." However, the Court noted that "if the Defendants do not hold to their word and cancel any planned future sale, North Dakota may bring this action for review of the specifically cancelled sales once this Court has the benefit of a complete record.
North Dakota filed a motion for preliminary injunction on 1/6/23, a hearing on the motions was held 2/21/23 in Minot with final briefing documents filed 3/14/23. On 3/27/23 U.S. District Judge Daniel Traynor in Bismarck ordered the Bureau of Land Management (BLM) to resume conducting quarterly oil and gas lease sales in North Dakota that had been illegally cancelled by BLM.
The most recent status hearing was 2/9/24. North Dakota has requested a transcript that we will make available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).
On 6/28/22 DAKOTA RESOURCE COUNCIL, CENTER FOR BIOLOGICAL DIVERSITY, CITIZENS FOR A HEALTHY COMMUNITY, LIVING RIVERS & COLORADO RIVERKEEPER, MONTANA ENVIRONMENTAL INFORMATION CENTER, RIO GRANDE RIVERKEEPER, SIERRA CLUB, WATERKEEPER ALLIANCE, WESTERN WATERSHEDS PROJECT, and WILDEARTH GUARDIANS sued DOI to challenge leasing decisions on 173 parcels including those in North Dakota. On 8/09/2022 the U.S. District Court in DC granted North Dakota's Motion to Intervene in the NGO's challenge to the legality of BLM's quarterly lease sales in Dakota Resource Council et al. v. U.S. Department of the Interior et al., 1:22-cv-01853-CRC.
On 9/6/22 the BLM and a group of NGOs filed a proposed settlement in the District Court of Montana in which BLM agrees to not issue drilling permits on 2019 and 2020 federal leases in North Dakota, Montana and South Dakota pending the completion of revised NEPA analyses that must take into account factors such as the social cost of carbon. This is a revival of the "sue and settle" litigation strategy whereby the Biden Administration settles litigation brought by NGOs in a manner that furthers the Administration's policy goals. The case was filed on 1/12/2021 by the same group of NGOs involved in North Dakota's leasing cases. The proposed settlement would cover 5 lease sales that authorized the sale of 113 leases encompassing 58,617 acres in North Dakota, Montana, and South Dakota. 55 North Dakota Parcels, 9,564.347 Federal Acres in North Dakota (leases Expire in 2029 and 2030), if permitting is delayed 7-8 years 130 wells will not be drilled, 58,329,000 barrels of oil will not be produced, GPT+OET+SalesTax+IncomeTax+NDRoyaltyShare+NDTLRoyalties @ $50/barrel = $8,006,217 per month = $960,746,074 over ten years.

BLM has posted for comment NEPA Number: DOI-BLM-HQ-3100-2023-0001-EA, Project Name: Supplemental Environmental Assessment Analysis for Greenhouse Gas Emissions Related to Oil and Gas Leasing in Seven States from February 2015 to December 2020, Project Type: Environmental Assessment, Project Status: In Progress - Public Review and Comment Period, Lead Office: HQ-310. Bureau of Land Management has released an updated environmental assessment for public comment. The additional review analyzes greenhouse gas emissions that may result from reasonably foreseeable development of 3,600 oil and gas leases that were sold in 74 lease sales between February 2015 and December 2020 that were the subject of litigation. The leases span approximately 3,433,615 acres in Colorado, Montana, New Mexico, Utah, Wyoming, North Dakota, and South Dakota. The environmental analysis looks at the development activity that would result in greenhouse gas emissions due to well development and production operations, as well as the end-use of the petroleum products produced from oil and gas leases. The supplemental analysis is in response to numerous court rulings and settlements. It incorporates new information and ensures consistency with recent court decisions, Executive and Secretarial Orders, and Department of the Interior policy. This analysis of greenhouse gas emissions supplements the greenhouse gas analysis provided in the previous National Environmental Policy Act (NEPA) documents supporting the 74 lease sales. The previous environmental assessments or determinations of NEPA adequacy, decision records, and findings of no significant impacts for the 74 lease sales are listed on BLM's State Oil and Gas Lease Sale website, which contains detailed information for the lease sales in each field office. Decisions related to the affected lease sales will be made separately and will include additional analysis of impacts to other resources, as appropriate. NDIC comments are available by request at [Contact | Department of Mineral Resources, North Dakota (nd.gov)](https://www.dmr.nd.gov/).

BLM published a new final rule 43 CFR Parts 3100, 3160 and 3170 to update and replace its regulations on venting and flaring of natural gas effective 1/17/16. The final rule can be viewed online at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/methane-and-waste-prevention-rule. North Dakota, Wyoming, Montana, Western Energy Alliance, and IPAA filed for a preliminary injunction to prevent the rule going into effect until the case is settled. A hearing in Casper, Wyoming was held 1/6/17. On 1/16/17 the court denied all of the petitioners' motions for preliminary injunctions. **On 2/3/17 the US House of Representatives voted 221-191 to approve a Congressional Review Act resolution against the rule.** On 3/28/17 President Trump issued an executive order which in part directs "The Secretary of the Interior shall review the following final rules, and any rules and guidance issued pursuant to them, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules". This rule is included in the list as item (iv). North Dakota plans to continue active participation in the litigation of this rule until the BLM takes final action eliminating the rule. **On 5/10/17 the Senate voted 51 to 49 against the CRA, allowing the rule to remain in effect.**

The Bureau of Land Management (BLM) is proposing new regulations very similar to the venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases rules of 2016 that were struck down by the court. The proposed regulations would be codified in the Code of Federal Regulations and would replace the BLM's current requirements governing venting and flaring, which are more than four decades old. NDIC comments are available by request at [Contact | Department of Mineral Resources, North Dakota (nd.gov)](https://www.dmr.nd.gov/)

BLM The Bureau of Land Management on 1/20/23 announced the **North Dakota Draft Resource Management Plan** and its associated draft environmental impact statement are available for public comment for a 90-day period ending April 20, 2023. **The comment period has been extended to end 5/20/23.** The draft resource management plan and draft environmental impact statement address management of approximately 58,500 acres of BLM-administered surface and 4.1 million acres of federal mineral estate in North Dakota for the next 20 to 30 years. Key issues raised during the public scoping period included mineral and energy resources, wildlife, recreation, water resources, air, and climate. In response to Tribal concerns, a "no surface occupancy" lease stipulation within a half mile of the Missouri River, Lake Sakakawea, and Lake Oahe has been added to the alternatives included in the documents. This stipulation is consistent with the Mandan, Hidatsa and Arikara Nation's Tribal Resolution and recognizes the regional importance of the Missouri River as a major supply of public drinking water. NDIC comments are available by request at [Contact | Department of Mineral Resources, North Dakota (nd.gov)](https://www.dmr.nd.gov/)

BLM On 4/3/23 The Bureau of Land Management (BLM) proposed new regulations that, pursuant to the Federal Land Policy and Management Act of 1976 (FLPMA), as amended, and other relevant authorities, would advance the BLM's mission to manage the public lands for multiple use and sustained yield by prioritizing the **health and resilience of ecosystems across those lands.** To ensure that health and resilience, the proposed rule provides that the BLM will protect intact landscapes, restore degraded habitat, and make wise management decisions based on science and data. To support these activities, the proposed rule would apply land health standards to all BLM-managed public lands and uses, clarify that conservation is a "use" within FLPMA's multiple-use framework, and revise existing regulations to better meet FLPMA's requirement that the BLM prioritize designating and protecting Areas of Critical Environmental Concern (ACECs). The proposed rule would add to provide an overarching framework for multiple BLM programs to promote ecosystem resilience on public lands. NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov) North Dakota has responded to a request to become a cooperating agency and has signed a MOU.

BLM On 7/24/23 The Bureau of Land Management (BLM) proposed to revise the BLM's **oil and gas leasing regulations.** Among other things, the proposed rule would reflect provisions of the Inflation Reduction Act pertaining to royalty rates, rentals, and minimum bids, and would update the bonding requirements for leasing, development, production, as well as revise some operating requirements. **North Dakota's requested comment period extension was denied and comments were filed 9/22/2023.** NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

Congress On 08/07/2022 the US Senate and on 08/12/2022 the US House passed HR 5376 which is expected to be signed into law by the president and contains numerous provisions that will negatively impact oil and gas producers and transporters. NDIC is in the process of analyzing the potential impact of Section 10101. CORPORATE ALTERNATIVE MINIMUM TAX, Section 10201 EXCISE TAX ON REPURCHASE OF CORPORATE STOCK, Section 13104 CREDIT FOR CARBON OXIVDE SEQUESTRATION, Section 13502 ADVANCED MANUFACTURING PRODUCTION CREDIT critical minerals, Section 60113 METHANE EMISSIONS REDUCTION PROGRAM, Section 50262 MINERAL LEASING ACT MODERNIZATION, on North Dakota's mineral industries.

CEQ On 7/31/23 the Council on Environmental Quality (CEQ) is proposing this ''Bipartisan Permitting Reform Implementation Rule'' to revise its regulations for implementing the procedural provisions of the **National Environmental Policy Act (NEPA)**, including to implement the Fiscal Responsibility Act's amendments to NEPA. CEQ invites comments on the proposed revisions. **North Dakota's comments were filed 9/29/2023.** NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

DPGL On 10/20/23 Dakota Prairie Grasslands announced the start of a 2-3 year process to develop a Travel Management Plan. North Dakota is negotiating a MOU to be a cooperating agency in the process.

EPA On 12/2/23 EPA released its final rule entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions" (2023 Methane Rule). On 12/6/22 The EPA issued a proposal to update, strengthen, and expand the standards proposed on November 15, 2021 which are intended to significantly reduce emissions of greenhouse gases (GHGs) and other harmful air pollutants from the Crude Oil and Natural Gas source category. First, the EPA proposes standards for certain sources that were not addressed in the November 2021 proposal. Second, the EPA proposes revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super emitter response program. Third, the EPA proposes to modify and refine certain elements of the proposed standards in response to information submitted in public comments on the November 2021 proposal. Finally, the EPA proposes details of the timelines and other implementation requirements that apply to states to limit methane pollution from existing designated facilities in the source category under the Clean Air Act (CAA). NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov). North Dakota is part of a coalition of states lead by West Virginia that are challenging the rules.

EPA On 5/23/23 the Environmental Protection Agency (EPA) issued a proposal titled, "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy

Rule". NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

PHMSA On 5/18/23 PHMSA proposed regulatory amendments that implement congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 to **reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, regulated (Types A, B, C and offshore) gas gathering pipelines, underground natural gas storage facilities, and liquefied natural gas facilities.** Among the proposed amendments for part 192-regulated gas pipelines are strengthened leakage survey and patrolling requirements; performance standards for advanced leak detection programs; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; and clarified requirements for investigating failures. Finally, PHMSA proposes expanded reporting requirements for operators of all gas pipeline facilities within DOT's jurisdiction, including underground natural gas storage facilities and liquefied natural gas facilities. **North Dakota's comments were filed 8/16/2023.** NDIC comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

SEC On Sept. 27, the New York Stock Exchange quietly submitted a substantial and financially material proposed change to its rules. The proposal would allow the formation of a new type of company. Natural Asset Companies, or NACs, would purchase the rights to control public and private lands, such as parks, forests and farms. But a NAC wouldn't be able to put the land to economic use. Instead, it would preserve its acquisitions to maximize the value of the land's "ecological services." NACs would register to go public on the NYSE. The money raised would purchase land and effectively lock it away from human impact. Grazing, energy extraction and other economically critical activities would disappear on NAC-protected land. Farmland used to feed the nation and world would go back to natural landscape, erasing human activity. The resulting conversion of investor money into unusable wildlands has the potential to be one of the most significant misallocations of capital in history. Normally, corporations are formed for investors to make money. But since NACs are clearly noneconomic, a rule is required to allow their formation. The land placed in a NAC, a private entity, must support only "replenishable" activities. Since no economic activity can occur, the property is assigned an arbitrary value and traded on that basis. In any other situation, this proposal would be identified as sanctioning fraud. Why would anyone invest in a company that can't make money? Initial buyers would likely be "impact investors," committed to sacrificing returns to advance the climate agenda. But it seems clear the goal is to sell NACs to endowments, sovereign wealth funds, pension funds and other investors demanding greater direct and immediate ESG presence in their portfolio. Demand from "values-driven investing" alone could drive up NAC share prices even as the value of the assets they purchase decrease by virtue of the NAC's ownership of them. More disturbing, reducing U.S. mineral extraction could be intriguing to Chinese, Russian or Saudi sovereign wealth funds. Environmental offsets in the form of carbon credits or government transfers for "conservation uses" could also generate ostensible revenues. The supposedly temporary Wind Production Tax Credit is an example of government policy used to benefit dubious investment choices at the behest of well-connected private-equity firms. Both private and public land is eligible for a NAC to purchase. Federal and state governments will surely sell public land to NACs, appeasing environmentalist constituencies under the guise of generating revenue. If NACs market themselves successfully, a significant amount of land will be removed from productive use. In western states like Utah, where the federal government owns 67% of the state, the effect could be devastating. Rural communities in the West, deprived of property tax revenue on vast federal land, pay for public improvements primarily through levies from extracting minerals on state land. The Biden administration's attack on energy has already reduced this essential revenue. The federal government has long fought the purchase of public land by private parties, and this is a dramatic change in policy. **On 1/17/24 SEC withdrew the proposed rule. North Dakota's comments were filed 1/17/24.** ND comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

USFWL On 6/22/23 the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS; collectively, the ''Services''), propose to revise portions of our regulations that implement the **Endangered Species Act** of 1973, as amended (Act). The proposed revisions to the regulations clarify, interpret, and implement portions of the Act concerning the procedures and criteria used for listing, reclassifying, and delisting species on the Lists of Endangered and Threatened Wildlife and Plants and designating critical habitat,the interagency consultation processes, reinstate the general application of the ‘‘blanket rule’’ option for protecting newly listed threatened species pursuant to section 4(d) of the Act, with the continued option to promulgate species-specific rules. We are also proposing to extend to federally recognized Tribes the exceptions to prohibitions for threatened species that the regulations currently provide to the employees or agents of the Service and other Federal and State agencies to aid, salvage, or dispose of threatened species. We are also proposing minor changes to clarify or correct the existing regulations for endangered and threatened species; these proposed minor changes would not alter the substance or scope of the regulations. We also request comments on an additional provision under consideration, but not currently proposed, that would extend to federally recognized Tribes the exceptions to prohibitions for threatened species that the regulations currently provide to employees or agents of the Service, the National Marine Fisheries Service, and State agencies for take associated with conservation-related activities, streamline our process for permitting of rights-of-way across National Wildlife Refuge System lands and other Service administered lands. By aligning Service processes more closely with those of other Department of the Interior (DOI) bureaus, to the extent practicable and consistent with applicable law, we will reduce the amount of time the Service requires to process applications for rights-of-way across Service-managed lands. We originally proposed revisions that included requiring a preapplication meeting and use of a standard application, allowing electronic submission of applications, and providing the Service with additional flexibility, as appropriate, to determine the fair market value or fair market rental value of rights-of-way across Service-managed lands. We now further propose new permit terms and conditions and other regulatory changes. **North Dakota signed onto comments filed by Alabama on 8/21/2023.** Comments are available by request at Contact | Department of Mineral Resources, North Dakota (nd.gov).

Lynn D. Helms, PhD
Director
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From: Ron Ness
To: Reiten, John R.
Cc: Norrell, Ryan; Beehler, Jace
Subject: Re: Natural Asset Companies- Governor Burgum Comments
Date: Friday, January 26, 2024 10:55:18 AM

Great work..

From: Reiten, John R. <jreiten@nd.gov>
Sent: Friday, January 26, 2024 10:42:25 AM
Cc: Norrell, Ryan <ryan.norrell@nd.gov>; Beehler, Jace <jabeehler@nd.gov>
Subject: Natural Asset Companies- Governor Burgum Comments

Good morning and happy Friday,

I have attached two documents to this email detailing our significant concerns regarding the proposed Natural Asset Companies rule. Fortunately, the rule was withdrawn as the comment deadline closed on January 17th; however, we still submitted these comments for inclusion in the public and administrative records.

The first document is our North Dakota special and unique concerns regarding the rule, and the second document is a coalition letter Governor Burgum signed with 6 other Governors.

Feel free to contact us if you have any questions.

Thank you,

John Reiten

From: Reiten, John R.
To: Beehler, Jace; Nowatzki, Mike G.
Cc: Norrell, Ryan
Subject: FW: EPA 2023 Final Methane Rule- assessment & recommendation URGENT
Date: Monday, January 15, 2024 10:26:56 AM

From: Wrigley, Drew H. <dwrigley@nd.gov>
Sent: Monday, January 15, 2024 10:22 AM
To: Norrell, Ryan <ryan.norrell@nd.gov>; Reiten, John R. <jreiten@nd.gov>; Helms, Lynn D. <lhelms@nd.gov>; Glatt, Dave D. <dglatt@nd.gov>; Seby, Paul (Shld-DEN-Env) <sebyp@gtlaw.com>
Subject: Re: EPA 2023 Final Methane Rule- assessment & recommendation URGENT

[redacted]

Drew H. Wrigley
Attorney General
North Dakota

From: sebyp@gtlaw.com <sebyp@gtlaw.com>
Sent: Sunday, January 14, 2024 3:48:39 PM
To: Wrigley, Drew H. <dwrigley@nd.gov>; Norrell, Ryan <ryan.norrell@nd.gov>; Reiten, John R. <jreiten@nd.gov>; Helms, Lynn D. <lhelms@nd.gov>; Glatt, Dave D. <dglatt@nd.gov>
Subject: EPA 2023 Final Methane Rule- assessment & recommendation URGENT

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[redacted]

[redacted]

[redacted]

Paul M. Seby
Tel 303.572.6584

From: Seby, Paul (Shld-DEN-Env) <sebyp@gtlaw.com>
Sent: Saturday, December 2, 2023 11:17 AM
To: Drew H. Wrigley <dwrigley@nd.gov>; Ryan Norrell <ryan.norrell@nd.gov>; John Reiten <jreiten@nd.gov>; Lynn D. Helms <lhelms@nd.gov>; Dave Glatt <dglatt@nd.gov>
Subject: EPA 2023 Final (Pre-Publication) Methane Rule- assessment & recommendation

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

From: Beehler, Jace
To: Reiten, John R.; Nowatzki, Mike G.
Subject: FW: DOE Invests $800,000 for Workforce Development Opportunities in Energy Communities Across the United States
Date: Thursday, January 11, 2024 12:07:00 PM
Attachments: image001.png
image002.png
image003.png
image004.png
image005.png
image006.png
image007.png
image008.png

FYI.... Potential social and/or SOTS discussion

From: Teigen, Joshua L. <jlteigen@nd.gov>
Sent: Thursday, January 11, 2024 12:03 PM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: FW: DOE Invests $800,000 for Workforce Development Opportunities in Energy Communities Across the United States

Situational awareness, pretty great testimony for the state. Could be State of the State material.

From: Todd Malan <malan@talonmetals.com>
Sent: Thursday, January 11, 2024 11:56 AM
To: Teigen, Joshua L. <jlteigen@nd.gov>; Oakland, Tom J. <thomas.oakland@nd.gov>; Garman, Rich W. <rgarman@nd.gov>
Cc: Jason Ehlert <Jason@ndbtu.org>; Ron Rauschenberger <rrausche@yahoo.com>; granville <granville@cityofbeulah.com>; Henri van Rooyen <vanrooyen@talonmetals.com>
Subject: RE: DOE Invests $800,000 for Workforce Development Opportunities in Energy Communities Across the United States

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Josh: Thanks so much for the kind words and recognition that we are trying to do things differently and address some of the painful and unfortunate history of the mining sector. The mineral intensity of some of the new energy systems is an unique opportunity for companies like Talon and states like North Dakota that are blessed by Mother Nature to have the ability to access rare earths and lithium that is infinitely recyclable and therefore a sustainable source for future energy systems. We are so grateful for you and your teams support for what Talon is trying to do in Mercer county and we are continuously blown away by how the state interests work together seamlessly – from your excellent team, to Beaver and his team in Mercer County to the Congressional delegation to Chairman Fox and MHA leadership – everyone is aligned, savvy and working together to for mutual benefit. It's a real model for the country to demonstrate that we can take on China and do them right! Look forward to connecting in person when I am next in North Dakota. Best ,Todd

Todd M. Malan
Chief External Affairs Officer & Head of Climate Strategy
Talon Metals
Washington D.C./Tamarack, MN
www.talonmetals.com
Phone: +12027148187
Email: malan@talonmetals.com
(TSX:TLO/OTC:TLOFF)

From: Teigen, Joshua L. <jlteigen@nd.gov>
Sent: Thursday, January 11, 2024 9:42 AM
To: Todd Malan <malan@talonmetals.com>; Oakland, Tom J. <thomas.oakland@nd.gov>; Garman, Rich W. <rgarman@nd.gov>
Cc: Jason Ehlert <Jason@ndbtu.org>; Ron Rauschenberger <rrausche@yahoo.com>; granville <granville@cityofbeulah.com>; Henri van Rooyen <vanrooyen@talonmetals.com>
Subject: RE: DOE Invests $800,000 for Workforce Development Opportunities in Energy Communities Across the United States

Todd,

This is tremendous news! Thank you for sharing. This is a testament not just to ND and MHA, but also Talon and your efforts to build a true partnership with the state. Very grateful for you guys and your commitment, please let us know how we can further assist.

Josh

From: Todd Malan <malan@talonmetals.com>
Sent: Thursday, January 11, 2024 11:12 AM
To: Oakland, Tom J. <thomas.oakland@nd.gov>; Garman, Rich W. <rgarman@nd.gov>; Teigen, Joshua L. <jlteigen@nd.gov>
Cc: Jason Ehlert <Jason@ndbtu.org>; Ron Rauschenberger <rrausche@yahoo.com>; granville <granville@cityofbeulah.com>; Henri van Rooyen <vanrooyen@talonmetals.com>
Subject: FW: DOE Invests $800,000 for Workforce Development Opportunities in Energy Communities Across the United States

Josh/Tom/Rich: Hope all well. Happy New Year! Good news from DOE today. Our proposal with MHA Nation, ND Building Trades and City of Beulah Economic Development (and Talon Metals) to train tribal members for roles in construction and manufacturing was selected today for $150k in funding for workforce training in energy communities. This was an idea from Jason Ehlert at ND Building Trades is being realized right now and the DOE funding will help build it up in North Dakota. We hear a lot about tribes having concerns about mining or refining due to concerns about negative impacts on the environment – rightfully so given their members deep connection to the natural environment. But tribes also want and deserve to be a part of economic benefits. MHA's willingness to work with us on a program like this is a testament to how tribes can work with other stakeholders, including project sponsors like Talon, to ensure that tribal members are part of the economic benefits of new economic investment. Kudos to Jason and Beaver who led this effort and happy to discuss. To me this is just another example of how North Dakota is leading the nation in smart economic development. Best, Todd

---

From: DOE, Office of Fossil Energy and Carbon Management <FECM@public.govdelivery.com>
Sent: Thursday, January 11, 2024 9:31 AM
To: Carly Good <cgood@vennstrategies.com>
Subject: DOE Invests $800,000 for Workforce Development Opportunities in Energy Communities Across the United States

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Office of Fossil Energy and Carbon Management

For Immediate Release

1/11/2024

Contact

FECMCommunications@hq.doe.gov

U.S. DEPARTMENT OF ENERGY INVESTS $800,000 FOR WORKFORCE DEVELOPMENT OPPORTUNITIES IN ENERGY COMMUNITIES ACROSS

THE UNITED STATES

Eight local government and non-profit organizations will receive funding and technical assistance toward repurposing existing energy facilities, equipment, and infrastructure

WASHINGTON, D.C. – The U.S. Department of Energy's (DOE) Office of Fossil Energy and Carbon Management (FECM) today announced $800,000 in federal funding for eight local government and non-profit organizations representing communities across the country, from Alaska to Pennsylvania, that will each create a roadmap toward repurposing their existing energy assets. The Capacity Building for Repurposing Energy Assets initiative will assist these communities, where a significant portion of their local economy has historically been supported by energy assets, such as coal, oil, and/or natural gas power facilities and accompanying equipment and infrastructure. This funding will help the communities build technical capacity and develop a workforce necessary to help revitalize energy systems, address environmental impacts, and tackle challenges associated with energy assets that have been retired, or are slated for retirement. This effort advances FECM's mission of minimizing environmental and climate impacts of energy systems and industrial processes, while working to achieve net-zero emissions across our economy. It also supports DOE's broader mission of ensuring efficient transformation of the energy system, while prioritizing labor and community engagement.

"We're excited to partner with energy communities across the nation as they advance plans to repurpose their energy assets and develop new infrastructure as we continue to work toward a clean energy and industrial economy," said **Brad Crabtree, Assistant Secretary of Fossil Energy and Carbon Management**. "The local initiatives funded through this program will help drive regional economic growth and technological innovation, while capitalizing on the skillsets of the existing workforce, providing new jobs and opportunities in areas such as sustainable energy technology development and advanced manufacturing."

The retirement of energy assets means that energy transmission and distribution infrastructure, electrical interconnection equipment, site and permitting licenses, and other related infrastructure may be available for alternative uses. At the same time, these communities must find opportunities to replace lost revenues and provide jobs for highly specialized workers. The Capacity Building for Repurposing Energy Assets initiative is providing these communities access to planning and other resources they need to develop a clean energy roadmap—giving them the chance to be active participants in crafting their own economic future.

The following organizations each were selected to receive $100,000 in federal funding for achieving development milestones toward plans for repurposing their community's energy assets:

- **Beaver County Corporation for Economic Development (Shippingport, Pennsylvania)** is planning to develop the multi-hundred-acre Shippingport Industrial Park to create a new epicenter for Beaver County and the greater Pittsburgh region, targeting the manufacturing, energy, construction, and transportation/warehousing sectors.
- **The City of Beulah, Department of Economic Development** (**Beulah, North Dakota)** will partner with North Dakota's Building Trades Unions, the Nueta Hidatsa Sahnish College, and Talon Metals to implement a program to recruit, train, and

place Native Americans in union jobs in the construction industry and operations such as the Talon Metals processing facility.

- **Associated Governments of Northwest Colorado (Craig, Colorado)** will bring together a diverse range of community stakeholders, including local government officials, business leaders, representatives from affected industries, environmental groups, and residents to develop a transformation plan for decommissioning of the Craig Station Power Plant, planned for retirement in 2025.
- **Grow Rural PA (Ridgeway, Pennsylvania)** plans to support the rural communities of Mountain View, Womer, and Swampoodle through the development of new green hydrogen infrastructure to anchor feedstock production for regional advanced manufacturing.
- **Floyd County Fiscal Court (Prestonsburg, Kentucky)** plans to repurpose some coal mining sites (with more than 100 closed since 2014) for economic development through metals manufacturing and others for future economic growth.
- **Southeastern Utah Economic Development District (Price, Utah)** plans to commission a nuclear powerplant, repowering the Hunter Power Plant in Castle Dale, Utah and validating the design, construction, and operational features of the Natrium demonstration project in Kemmerer, Wyoming.
- **Alaska Municipal League (Juneau, Alaska)** plans to support efforts to retire a coal-fired power plant in Healy, Alaska and develop a new battery energy storage system and wind project, providing community engagement, strategies for economic and workforce development activities, and lessons learned.
- **The Center for Applied Research and Technology, Inc. (Bluefield, West Virginia)** plans to coordinate efforts with the decommissioning of coal-fired power plants such as the plant in Glen Lyn, Virginia, while also exploring options for developing building material components and other useful products made from legacy coal combustion residuals at nearby manufacturing sites.

The Capacity Building for Repurposing Energy Assets initiative is managed by ENERGYWERX in partnership with DOE, a collaboration made possible through an innovative Partnership Intermediary Agreement set up by DOE's Office of Technology Transitions. This agreement enables ENERGYWERX to broaden DOE's engagement with innovative organizations and non-traditional partners, facilitating the rapid development, scaling, and deployment of clean energy solutions.

DOE intends to re-open the Capacity Building for Repurposing Energy Assets program for additional submissions in early 2024. Subsequent updates and announcements for the this initiative will be posted on the ENERGYWERX website. Questions about the initiative should be submitted to info@energywerx.org.

FECM minimizes environmental and climate impacts of fossil fuels and industrial processes while working to achieve net-zero emissions across the U.S. economy. Priority areas of technology work include carbon capture, carbon conversion, carbon dioxide removal, carbon dioxide transport and storage, hydrogen production with carbon management, *methane emissions reduction, and critical minerals production. To learn more, visit the [FECM website](), [sign up]() for FECM news announcements, and visit the [National Energy Technology Laboratory website]().*

###

OFFICE OF FOSSIL ENERGY AND CARBON MANAGEMENT
1000 Independence Avenue, SW
Washington, D.C. 20585

202-586-6660

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From: Beehler, Jace
To: Liz Markham
Subject: RE: GNDC Public Policy
Date: Monday, January 8, 2024 8:33:00 AM
Attachments: image003.png

Thank you!

From: Liz Markham <Liz@ndchamber.com>
Sent: Monday, January 8, 2024 8:21 AM
To: Beehler, Jace <jabeehler@nd.gov>
Cc: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: Re: GNDC Public Policy

You don't often get email from liz@ndchamber.com. Learn why this is important

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Greetings, Jace

Thank you for the email and I know Amanda appreciates the thoughts! She is doing very well!

We'll be hosting our Policy Summit on September 10th this year. Please let me know if there is any information you need. I hope you have a wonderful week!

Deepest Regards,

Liz Markham

Membership Director | Greater North Dakota Chamber
PO Box 2639, Bismarck ND 58502
ndchamber.com | liz@ndchamber.com | 701.222.0929 (o) - 701.425.1775 (c)

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Monday, January 8, 2024 12:28 AM
To: Liz Markham <Liz@ndchamber.com>
Cc: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: FW: GNDC Public Policy

Hello Liz,

Please see the message below. Hoping all is ok with Amanda!

Jace

From: Beehler, Jace
Sent: Monday, January 8, 2024 12:24 AM
To: Amanda Remynse <amanda@ndchamber.com>
Cc: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: GNDC Public Policy

Hello Amanda,

Can you share with me when you plan on holding your 2024 public policy conference? We are working on the schedule for our conferences this year and want to ensure we don't duplicate.

Thanks,
Jace

Jace Beehler
Chief of Staff
Office of the Governor
701.328.2201 • 701.610.9431(m) • jabeehler@nd.gov • www.nd.gov

From: Amanda Remynse
To: Beehler, Jace
Subject: Automatic reply: GNDC Public Policy
Date: Monday, January 8, 2024 12:24:30 AM

Hi - thanks for reaching out to me. This OOO is brought you by the letter 'm' - as in medical leave! I'm currently out of office and will be returning next month.

HOWEVER, I work with a great team so they can get answers or address issues... start with Liz@ndchamber.com (our membership director) or AmyJo@ndchamber.com (operations/events).

In the meantime, check out our website for resources related to the Greater North Dakota Chamber - www.ndchamber.com.

OH - and be sure you catch my latest blog post on business contemplation and how my daughter LOATHES red lights (my mom said it's a good read) - https://www.ndchamber.com/blog/brass-tacks-2463/post/fall-report-on-business-launch-with-the-missing-column-38026

AND you can't forget our upcoming Policy Outlooks or our upcoming Workforce Showcase - registrations are open https://www.ndchamber.com/events/

Amanda Remynse
VP (operations & outreach) - **Greater North Dakota Chamber**

From: Weber, Aaron (Hoeven)
To: Beehler, Jace
Subject: FW: Register for API"s State of American Energy (1/10)
Date: Wednesday, January 3, 2024 4:12:01 PM

FYI

From: American Petroleum Institute <registrar@api.org>
Sent: Wednesday, January 3, 2024 2:35 PM
To: Weber, Aaron (Hoeven) <Aaron_Weber@hoeven.senate.gov>
Subject: Register for API's State of American Energy (1/10)

View in browser

The American Petroleum Institute's

2024 State of American Energy

WEDNESDAY, JANUARY 10, 2024

Join us for API's annual policy-setting event as we shed light on solutions to expand energy access, strengthen national security and accelerate American infrastructure. Speakers include **API President and CEO Mike Sommers**, **Governor J. Kevin Stitt** of Oklahoma and U.S **Senators John Hickenlooper (CO) and Bill Cassidy**

(LA), who will discuss a bipartisan path on energy.

Program: 8:30 – 10:00 a.m. ET

Doors open at 7:30 a.m. for an interactive breakfast reception with industry leaders and policymakers from across the country.

Capital Turnaround

700 M Street SE

Washington, DC 20003

Parking available

Register Today

Please RSVP by January 8, 2024

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From: Arik Spencer
To: Beehler, Jace
Subject: RE: Touchbase
Date: Wednesday, January 3, 2024 3:01:01 PM
Attachments: image002.png

10:30 on Friday works. City Brew or Anima Cucina?

Arik Spencer
CEO, President | Greater North Dakota Chamber
PO Box 2639, Bismarck, ND 58502
ndchamber.com | arik@ndchamber.com | 701.222.0929

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Wednesday, January 3, 2024 2:49 PM
To: Arik Spencer <arik@ndchamber.com>
Subject: RE: Touchbase

Hi Arik,

Sorry for the delay. How would 10:30 or 3:30 on Friday work?

Thanks,
Jace

From: Arik Spencer <arik@ndchamber.com>
Sent: Wednesday, January 3, 2024 2:36 PM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: RE: Touchbase

Hi Jace,

Just following up. Thanks.

Arik Spencer
CEO, President | Greater North Dakota Chamber
PO Box 2639, Bismarck, ND 58502
ndchamber.com | arik@ndchamber.com | 701.222.0929

From: Arik Spencer
Sent: Wednesday, December 27, 2023 11:47 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: RE: Touchbase

Hi Jace,

I hope you had a merry Christmas also, and I would love to connect next week. I'm pretty open the afternoons of the 3rd to 5th, so let me know what works for you.

Arik

Arik Spencer
CEO, President | Greater North Dakota Chamber
PO Box 2639, Bismarck, ND 58502
ndchamber.com | arik@ndchamber.com | 701.222.0929

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Tuesday, December 26, 2023 9:31 PM
To: Arik Spencer <arik@ndchamber.com>
Subject: Touchbase

Hi Arik,

I hope that you had a Merry Christmas and are preparing for a great New Year! I wanted to reach out to see if you wanted to touch base maybe next week? As we head into the new year, our strategy reviews, SOTS and budgeting, I want to ensure we are in sync with you and your members.

Thanks,
Jace

Jace Beehler

Chief of Staff

Office of the Governor

701.328.2201 • 701.610.9431(m) • jabeehler@nd.gov • www.nd.gov

From: Rolf Hanson
To: Beehler, Jace
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)
Date: Tuesday, January 2, 2024 10:39:16 AM
Attachments: image001.png
image002.png

Jace,

I completely understand and thank you and the Governor for the consideration. We will keep you in mind for future events.

Kind Regards,

Rolf Hanson
Vice President, State Government Relations
American Petroleum Institute
o: 202.682.8219
m: 571.512.8468

www.api.org

signature_1982813188

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Tuesday, January 2, 2024 11:36 AM
To: Rolf Hanson <Hansonr@api.org>
Subject: Re: 2024 API State of American Energy Speaker Invitation (1/10)

Hello Rolf,

My sincere apologies for the delay. While the Governor is incredibly grateful for the opportunity to speak but I regret to share that we were unable to get the schedule to work out this year. We hope that you will consider the Governor in the future.

All the best for a great event.
Jace

Get Outlook for iOS

From: Rolf Hanson <Hansonr@api.org>
Sent: Tuesday, January 2, 2024 9:18:35 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: FW: 2024 API State of American Energy Speaker Invitation (1/10)

Happy New Year Jace.

We are finalizing the State of American Energy which will include sending a media advisory out this afternoon with the list of elected officials and would like to finalize if the governor is available for this event?

Regards,

Rolf Hanson
Vice President, State Government Relations
American Petroleum Institute
o: 202.682.8219
m: 571.512.8468

www.api.org

signature_1982813188

From: Rolf Hanson <Hansonr@api.org>
Sent: Friday, December 29, 2023 6:04 PM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: Re: 2024 API State of American Energy Speaker Invitation (1/10)

Jace,

Checking in before the weekend to see if you have been able to confirm availability or have any other questions?

Regards,
Rolf

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From: Beehler, Jace <jabeehler@nd.gov>
Sent: Thursday, December 28, 2023 5:06:21 PM
To: Rolf Hanson <Hansonr@api.org>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Hello Rolf,

My apologies for the delay. We are hoping to have confirmation on a few things to get you an answer tonight or tomorrow.

Do you have any information on the audience of this event? Who are the primary attendees?

Thank you again for your understanding!
Jace

From: Rolf Hanson <Hansonr@api.org>
Sent: Monday, December 18, 2023 12:19 PM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Jace,

I wanted to circle back as we start to pull together the final agenda ahead of the holiday break to see if you have any updates on the Governor's availability.

Thank you,

Rolf Hanson
Vice President, State Government Relations
American Petroleum Institute
o: 202.682.8219

m: 571.512.8468

www.api.org

signature_1982813188

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Monday, December 11, 2023 5:12 PM
To: Rolf Hanson <Hansonr@api.org>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Caution: This email originated from outside of API-make sure the content is safe. Please use the Phish Alert button if suspicious.

Thank you for pinging us. I will circle back with our team and work to get back to you ASAP.

All the best,
Jace

From: Rolf Hanson <Hansonr@api.org>
Sent: Monday, December 11, 2023 7:46 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

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Jace,

I hope all is well. I wanted to follow up to see if you have been able to confirm the Governor's availability for this event. We appreciate your consideration!

Regards,

Rolf Hanson
Vice President, State Government Relations
American Petroleum Institute
o: 202.682.8219
m: 571.512.8468

www.api.org

signature_1982813188

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Tuesday, November 28, 2023 6:26 AM
To: Kristin A. Westmoreland <WestmorelandK@api.org>
Cc: Rolf Hanson <Hansonr@api.org>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Thank you for the invitation. We will check on the schedule and get back as soon as we can.

Thanks,
Jace

From: Kristin A. Westmoreland <WestmorelandK@api.org>
Sent: Monday, November 27, 2023 12:57 PM
To: Beehler, Jace <jabeehler@nd.gov>
Cc: Rolf Hanson <Hansonr@api.org>
Subject: 2024 API State of American Energy Speaker Invitation (1/10)

Jace –

I hope this email finds you well and that you had a great Thanksgiving!

API President and CEO Mike Sommers would like to invite Governor Burgum to join him as a speaker at API's 2024 State of American Energy (SOAE) the morning of January 10 in Washington, DC. This in-person event will have a broad range on attendees including industry experts, Congressional staff, policymakers, and press who would benefit from hearing Governor Burgum's insights. Please see the attached invitation for additional information.

Should you have any questions, please don't hesitate to reach out to myself or Rolf Hanson, API Vice President for State Government Relations.

All the best,
Kristin

Kristin Westmoreland
Vice President and Chief of Staff
703.300.0385
e: westmorelandk@api.org
www.api.org

From: Rolf Hanson
To: Beehler, Jace
Subject: FW: 2024 API State of American Energy Speaker Invitation (1/10)
Date: Tuesday, January 2, 2024 9:18:47 AM
Attachments: image001.png
image002.png

Happy New Year Jace.

We are finalizing the State of American Energy which will include sending a media advisory out this afternoon with the list of elected officials and would like to finalize if the governor is available for this event?

Regards,

Rolf Hanson
Vice President, State Government Relations
American Petroleum Institute
o: 202.682.8219
m: 571.512.8468

www.api.org

signature_1982813188

From: Rolf Hanson <Hansonr@api.org>
Sent: Friday, December 29, 2023 6:04 PM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: Re: 2024 API State of American Energy Speaker Invitation (1/10)

Jace,

Checking in before the weekend to see if you have been able to confirm availability or have any other questions?

Regards,
Rolf

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From: Beehler, Jace <jabeehler@nd.gov>
Sent: Thursday, December 28, 2023 5:06:21 PM
To: Rolf Hanson <Hansonr@api.org>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Hello Rolf,

My apologies for the delay. We are hoping to have confirmation on a few things to get you an answer tonight or tomorrow.

Do you have any information on the audience of this event? Who are the primary attendees?

Thank you again for your understanding!
Jace

From: Rolf Hanson <Hansonr@api.org>
Sent: Monday, December 18, 2023 12:19 PM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Jace,

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Thank you,

Rolf Hanson
Vice President, State Government Relations
American Petroleum Institute
o: 202.682.8219
m: 571.512.8468

www.api.org

signature_1982813188

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Monday, December 11, 2023 5:12 PM
To: Rolf Hanson <Hansonr@api.org>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Thank you for pinging us. I will circle back with our team and work to get back to you ASAP.

All the best,
Jace

From: Rolf Hanson <Hansonr@api.org>
Sent: Monday, December 11, 2023 7:46 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Jace,

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Regards,

Rolf Hanson
Vice President, State Government Relations
American Petroleum Institute
o: 202.682.8219
m: 571.512.8468

www.api.org

signature_1982813188

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Sent: Tuesday, November 28, 2023 6:26 AM
To: Kristin A. Westmoreland <WestmorelandK@api.org>
Cc: Rolf Hanson <Hansonr@api.org>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Thank you for the invitation. We will check on the schedule and get back as soon as we can.

Thanks,
Jace

From: Kristin A. Westmoreland <WestmorelandK@api.org>
Sent: Monday, November 27, 2023 12:57 PM
To: Beehler, Jace <jabeehler@nd.gov>
Cc: Rolf Hanson <Hansonr@api.org>
Subject: 2024 API State of American Energy Speaker Invitation (1/10)

Jace –

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Should you have any questions, please don't hesitate to reach out to myself or Rolf Hanson, API Vice President for State Government Relations.

All the best,

Kristin

Kristin Westmoreland
Vice President and Chief of Staff
703.300.0385
e: westmorelandk@api.org
www.api.org

From: Laura Lacher
To: Beehler, Jace; Greenberg, Zachary N.; Reiten, John R.
Cc: Levi Andrist; Dennis Pathroff; Amy Cleary; Brenda Elmer; anmauch@gmail.com; Tracey.Olson@guardianNRG.com; Jeff Zueger; Jodi Johnson (Jodi@redtrailenergy.com); rcarter@tharaldsonethanol.com; Keshav Rajpal
Subject: Follow-Up on E15 Support
Date: Thursday, May 30, 2024 3:49:35 PM
Attachments: E15 Support Letter.pdf
FINAL Governors Letter to EPA on RVP Waiver 4.28.22 merged.pdf
ND E15 RFA.pptx

Jace, John and Zach -

On behalf of the North Dakota Ethanol Producers Association (NDEPA) and North Dakota Corn Growers Association (NDCGA), I would like to thank you for the opportunity to meet and discuss the governor's reconsideration of supporting year-round E15 fuel for North Dakota. We believe that supporting year-round E15 fuel can significantly benefit North Dakota's agricultural and energy sectors.

Enclosed with this email, please find the following supporting documents:

1. Joint NDEPA/NDCGA Letter regarding E15 Support which was sent in April to your office
2. The original draft letter from 2022 supporting year-round E15 (our copy still includes Governor's original signature) This could be used to model a new one-page letter for North Dakota, should the Governor reconsider. This includes a link to the air quality modeling that has already been approved by the EPA for North Dakota and could be included in his letter.
3. Our PowerPoint presentation sharing additional information on the benefits of year-round E15

These documents provide detailed insights into the numerous advantages of adopting year-round E15, including boosting demand for locally produced ethanol, reducing greenhouse gas emissions, and improving air quality. We are confident that this information will be valuable in your decision-making process.

What's changed in the past two years since the original letter?

1. A precedent has been set with the 8 Midwest states that have secured permanent year-round E15 access beginning in 2025
2. The expectations have greatly increased from consumers and congress for a more sustainable fuel option
3. Inflation has hurt North Dakotans, something that wasn't as serious of a problem two years ago. North Dakota's E15 discount to E10 over the past year has averaged 16-18

cents per gallon (5-6% discount)

Regarding the questions on the EPA timeline from the Clean Air Act here is what I found:

- Section 211(h)(5)(B) of the Clean Air Act requires EPA to approve a request from a Governor to "opt-out" of the 1-psi waiver for E10 "not later than 90 days after the date of receipt of a notification from a Governor." So, it is correct that EPA has 90 days to respond to a Governor's request.
- However, the next section – 211(h)(5)(C) – says that the change "shall take effect on the **later** of: the first day of the first high ozone seasons for the area that begins after the date of receipt of notification; or 1 year after the date of receipt of the notification.

So, in practice: if North Dakota submitted a letter on June 3, 2024, the EPA would have until September 1, 2024, to respond to the request. But the earliest the RVP change could take effect, according to the statute, would be June 3, 2025, ("1 year after the date of receipt of the notification"). That's why getting a request in as soon as possible is very important if North Dakota wants to be part of year-round E15 for 2025.

The North Dakota Ethanol Producers Association remains committed to collaborating with your office and other stakeholders to ensure the successful implementation of this initiative. Should you require any additional information or support, please do not hesitate to reach out.

Thank you once again for your time and consideration.

NDePA
NORTH DAKOTA ETHANOL PRODUCERS ASSOCIATION
NORTH DAKOTA CORN GROWERS ASSOCIATION

April 26, 2024

Dear Governor Burgum,

The North Dakota Ethanol Producers and the North Dakota Corn Growers Association appreciate your efforts to establish North Dakota as a leader in agriculture and energy production, and we specifically thank you for your commitment to supporting growth and innovation in the corn ethanol industry. To ensure North Dakota maintains its role as a national leader in ethanol production and use, we are respectfully requesting that you utilize your authority under the Clean Air Act to provide the state's drivers with year-round access to gasoline containing 15 percent ethanol (E15).[1]

On February 29, 2024, the U.S. Environmental Protection Agency officially approved petitions from eight Midwest states to remove the 1-pound-per-square-inch (psi) volatility waiver for gasoline blends containing 10 percent ethanol (E10).[2] This action will facilitate uninterrupted, year-round sales of E15 in these states starting in 2025, ensuring that consumers in those areas have continuous access to lower-cost, cleaner-burning fuel all year long.

Unfortunately, North Dakota was not among the states that secured approval from EPA for year-round access to E15. But it's not too late for North Dakota to join these eight Midwest states, which include neighboring South Dakota and Minnesota, in offering more affordable fuel options year-round. To ensure North Dakota's ethanol producers, corn growers, and consumers aren't left behind, we ask that you submit a petition to EPA to eliminate the 1-psi volatility waiver for E10 and allow year-round E15 in North Dakota beginning in 2025.

There are a number of compelling reasons for North Dakota to take action immediately.

1. **Failure to act could lead to regional inconsistency and inefficiencies in the fuel supply.** Following U.S. EPA's approval of their petition, North Dakota's neighboring states of South Dakota and Minnesota will transition to a different grade (i.e., lower-volatility) of gasoline blendstock in 2025. The pipeline systems that supply much of North Dakota's gasoline blendstock also supply Minnesota, South Dakota, and the other states that successfully petitioned EPA. Thus, the gasoline product suitable for year-round E15 blending will already be flowing into the region in the primary pipeline systems (e.g., NuStar and OneOK) that serve major North Dakota fuel terminals. Any pipeline, terminal, and refining investments needed to accommodate lower-volatility gasoline in the upper Midwest region likely will be made whether North Dakota allows year-round E15 or not.

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[1] *See* Clean Air Act Section 211(h)(5).

[2] https://www.epa.gov/gasoline-standards/final-rule-response-request-states-removal-gasoline-volatility-waiver

2. **Failure to act could put North Dakota fuel retailers at a competitive disadvantage.** Retail gas stations in South Dakota and Minnesota will be able to sell lower-cost E15 to drivers year-round starting in 2025, while North Dakota stations will have to stop E15 sales from June 1-September 15. This could negatively affect the competitiveness of North Dakota fuel retailers, especially in metro areas that share a border with Minnesota (like Fargo and Grand Forks, which collectively represent roughly one-third of the North Dakota population).

3. **Without summertime access to E15, drivers in North Dakota could pay more for gasoline than drivers in neighboring states that have year-round E15**. E15 is typically priced 10-30 cents per gallon less than regular E10 gasoline. Without year-round E15 availability, North Dakota drivers would pay more for E10 than drivers in bordering states who are buying E15. For example, Casey's stations in the Fargo metro area are currently selling E15 for 15 cents per gallon less than E10.[3] Stations on the North Dakota side of the border will have to stop selling E15 on June 1, while stations just a few miles away on the Minnesota side of the border will continue offering the lower-cost fuel to customers. Studies show 64 percent of drivers will drive five minutes out of their way to save 5 cents per gallon on gasoline, meaning more North Dakotans will be crossing the border to buy their fuel (and convenience store products) in Minnesota.[4]

4. **Any marginal increase in refining and pipeline costs associated with lower-volatility gasoline would be more than offset by the lower cost of E15 at the pump**. A recent study by fuel market experts at ICF examined the likely response of the Midwest fuel supply chain to the action requested by the eight Governors in 2022. ICF found that "…most refineries, pipelines, and distribution terminals within the region should be able to fully switch over to the new lower-RVP gasoline specification with minimal challenges." Additionally, an analysis by oil industry consulting firm MathPro, Inc., found that the requested action would result in additional refining and infrastructure costs of just 2 cents per gallon of gasoline. This modest cost increase for fuel producers and distributors would be far outweighed by the consumer savings resulting from broader availability of E15.

5. **The air quality modeling that must accompany state petitions has already been conducted for North Dakota and accepted by U.S. EPA.** The original petition sent by Midwest governors to U.S. EPA in 2022 included the statutorily required air quality modeling results for North Dakota and seven other states, meaning the technical work to support a new petition from North Dakota has already been done.

6. **Federal legislation establishing year-round E15 nationwide appears unlikely to pass before 2025.** While a nationwide solution allowing year-round E15 would be preferable to state or regional approaches, legislation establishing such a fix (S. 2707) has stalled in the Senate and is unlikely to pass this Congress. The Senate bill has broad bipartisan support

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[3] Casey's mobile app. Viewed April 22, 2024.

[4] https://www.convenience.org/Media/Press-Releases/2022-Press-Releases/Convenience-Retailers-and-Consumers-Agree-A-Good-E

and has been endorsed by farm groups, ethanol producers, fuel retailers, and the American Petroleum Institute. However, a small group of merchant oil refiners and the Democratic majority leadership of the Senate committee with jurisdiction (i.e., the Environment and Public Works Committee) oppose the legislation and it remains at an impasse. We cannot afford to wait on Congress to solve this issue when states have the tools available to do so themselves.

As you can see, there are many good reasons to join your colleagues from the eight Midwest states who successfully petitioned the EPA to allow year-round E15. But time is of the essence. The federal statute essentially requires Governors to submit petitions removing the 1-psi waiver for E10 one full year before the action would be effective. Thus, for North Dakotans to enjoy uninterrupted access to E15 in the summer of 2025, a petition must be submitted as soon as possible.

Again, thank you for your leadership and we appreciate your consideration of this request. We stand ready to answer any questions you or your staff may have or provide additional information as needed.

Sincerely,

Tracey Olson, *NDEPA President*
Guardian Energy Hankinson
[redacted]
[redacted]

Ryan Carter, *NDEPA Vice President*
Tharaldson Ethanol Plant
[redacted]

Jeff Zueger, *NDEPA Sec./Treas.*
Harvestone Low Carbon Partners
[redacted]
[redacted]

Jodi Johnson, *NDEPA Director*
Red Trail Energy, LLC
[redacted]
[redacted]

Keshav Rajpal, *NDEPA Director*
Red River Biorefinery
[redacted]
[redacted]

Andrew Mauch, *NDCGA President*
anmauch@gmail.com
[redacted]

April 28, 2022

The Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Administrator Regan,

We are writing to thank you and the U.S. Environmental Protection Agency (EPA) for exercising your emergency waiver authority to waive the 9-psi Reid vapor pressure (RVP) limitation for gasoline blended with 15 percent ethanol (E15) for the 2022 summer ozone control season. This action will help provide relief, flexibility, and certainty in the fuel market as we are seeing record high gasoline prices in our states and around the country.

While this emergency RVP waiver will deliver economic relief and energy security benefits in the near term, a permanent solution allowing the year-round sale of E15 is also needed for long-term certainty. Accordingly, we are notifying the EPA, pursuant to Section 211(h)(5) of the Clean Air Act, that the RVP limitation established by Section 211(h)(4) increases emissions that contribute to air pollution in our states. Therefore, we respectfully request that EPA promulgate a regulation applying, in lieu of the RVP limitation established by Section 211(h)(4), the RVP limitation established by Section 211(h)(1) to all fuel blends containing gasoline and 10 percent ethanol that are sold, offered for sale, dispensed, supplied, offered for supply, transported, or introduced into commerce in Iowa, Nebraska, Illinois, Kansas, Minnesota, North Dakota, South Dakota, and Wisconsin beginning with the 2023 summer ozone control season.

According to a Health Effects Institute Panel on the Health Effects of Traffic-Related Air Pollution, "High gasoline vapor pressure causes high evaporative emissions from motor vehicles and is therefore a priority fuel quality issue. … Reductions in fuel volatility will significantly reduce evaporative emissions from vehicles. A reduction in vapor pressure is one of the more cost effective of the fuel-related approaches available to reduce hydrocarbon emissions."[1]

The emissions benefits of lowering gasoline vapor pressure by 1-psi were modeled for each of our states (see attachment). The analysis concluded that a 1-psi RVP reduction would be beneficial to air quality, as emissions of carbon monoxide (CO), oxides of nitrogen (NOx) and volatile organic compounds (VOCs) would be reduced.

[1] Health Effects Institute. HEI Panel on the Health Effects of Traffic-Related Air Pollution. (2010) "Special Report 17: Traffic-Related Air Pollution: A Critical Review of the Literature on Emissions, Exposure, and Health Effects."

Supporting documentation for this request is attached. We urge swift action to help lower fuel prices across the country, restore energy independence, and increase consumer access to our nation's homegrown biofuels. We appreciate your consideration of our request.

Sincerely,

Kim Reynolds
Kim Reynolds
Governor of Iowa

Pete Ricketts
Pete Ricketts
Governor of Nebraska

JB Pritzker
Governor of Illinois

Laura Kelly
Laura Kelly
Governor of Kansas

Tim Walz
Governor of Minnesota

Doug Burgum
Doug Burgum
Governor of North Dakota

Kristi Noem
Governor of South Dakota

Tony Evers
Tony Evers
Governor of Wisconsin

Emissions Impacts of the Elimination of the 1-psi RVP Waiver for E10

May 9, 2022

Janet Yanowitz, P.E., Ph.D.
Ecoengineering, Inc.

The U.S. EPA Motor Vehicle Emissions Simulator (MOVES) Version 3.0.3 model has been used to estimate the impact on air emissions from both onroad and nonroad sources if the 1-psi Reid vapor pressure (RVP) waiver for 10% ethanol blends were to be eliminated. MOVES3 is a complex emission modeling system intended to estimate air pollution emissions from mobile sources in the United States. It is based on many individual physical processes, which are then scaled up on the basis of fleet-average emission factors, and a database which includes information on the use-rates of different types of vehicles and the properties of the fuel used in each region of the country

The model was run for a single July weekday in 2023 in each of eight states. A summer day was chosen because the RVP limit of 10 psi for E10 fuels (9 psi for gasoline) is only applicable in the summer ozone season. This work included all emissions included in the MOVES modeling system with the exception of PM emissions from brakes and tires. Brake and tire emissions are unaffected by fuel changes and are a minor part of total PM emissions, so it was a modification that had little impact.

For this work MOVES3 default values for all local data were used, including things like meteorology, source-type populations, age distributions, vehicle type VMT, etc. , with the exception of the fuels data. Although the default fuels data were used for the base case runs, for the test case all 10 psi E10 fuels (i.e. not the reformulated gasoline, nor any other non-E10 fuels) in the database were adjusted to 9 psi using the "Fuels Wizard" tool in MOVES3. When the user adjusts a specific fuel characteristic, the Fuels Wizard adjusts other fuel properties based on EPA's refinery modeling. When RVP is adjusted using the Fuels Wizard, the model makes automatic adjustments to the T50 and the T90 of the fuel, but no other fuel properties.

Illinois and Wisconsin are the only states included in this analysis in which reformulated gasoline is used in part of the state. The 1-psi RVP waiver for E10 is not applicable to reformulated gasoline. Thus, while the RVP of the non-reformulated gasoline was changed for the test (9psi) case in these two states, the amount and RVP of the reformulated gasoline were unchanged between the base case and test (9psi) case.

The eight states evaluated were

1. Iowa,
2. Nebraska,
3. Kansas,
4. Wisconsin,
5. South Dakota,
6. Minnesota,

7. North Dakota, and
8. Illinois.

The MOVES model results showed that emissions of VOCs will be significant lowered with the elimination of the 1 psi waiver. NOx, CO and BTEX would also be consistently reduced, although to a lesser extent, in each one of these states if the vapor pressure of summer E10 were lowered to 9 psi. The one exception was a *de minimis* increase in benzene emissions of only 5/10,000 of the total benzene emissions in the case of Kansas. Similarly, there is a *de minimis* increase in emissions of PM2.5 and PM 10, of at most 22/10,000 of total PM emissions for the state of Wisconsin, and somewhat less in other states. If brake and tire emissions had been included it would have made the already small net increase in PM emissions even smaller, when expressed in percentage terms.

The tables below summarize the results of the MOVES3 runs that were made for this analysis. Table 1 includes only the onroad emissions, Table 2, the nonroad emissions and Table 3, the sum of onroad and noroad emissions.

The MOVES3 input and output files were forwarded to EPA on May 3, 2022 and can be accessed with a sharable link:

MOVES files_8 States RVP Notification_April 2022.

Table 1. Emissions (grams) of CO, NOx, PM, VOCs and BTEX from all onroad MOVES3.0.1 sources (except brake and tire particulate emissions) for a July weekday in 2023.

Onroad Base Case	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	1.465E+09	1.721E+08	3.779E+06	4.163E+06	9.207E+07	1.429E+06	9.905E+06	1.361E+06	5.171E+06
Iowa	5.468E+08	6.487E+07	1.442E+06	1.589E+06	3.278E+07	5.220E+05	3.533E+06	4.879E+05	1.855E+06
Kansas	5.378E+08	5.917E+07	1.305E+06	1.437E+06	3.238E+07	5.051E+05	3.527E+06	4.759E+05	1.811E+06
Minnesota	8.874E+08	1.050E+08	2.261E+06	2.492E+06	5.448E+07	9.383E+05	5.928E+06	8.167E+05	3.105E+06
Nebraska	3.380E+08	4.057E+07	8.842E+05	9.734E+05	2.059E+07	3.180E+05	2.234E+06	3.046E+05	1.160E+06
North Dakota	1.446E+08	1.959E+07	4.112E+05	4.526E+05	8.786E+06	1.506E+05	9.438E+05	1.312E+05	4.993E+05
South Dakota	1.601E+08	2.145E+07	4.522E+05	4.975E+05	9.699E+06	1.591E+05	1.047E+06	1.431E+05	5.440E+05
Wisconsin	9.249E+08	1.201E+08	2.581E+06	2.842E+06	5.755E+07	9.627E+05	6.186E+06	8.584E+05	3.264E+06
Onroad 9psi Case	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	1.459E+09	1.719E+08	3.794E+06	4.180E+06	9.177E+07	1.467E+06	9.819E+06	1.358E+06	5.157E+06
Iowa	5.420E+08	6.473E+07	1.456E+06	1.604E+06	3.260E+07	5.556E+05	3.466E+06	4.850E+05	1.843E+06
Kansas	5.340E+08	5.907E+07	1.314E+06	1.448E+06	3.197E+07	5.292E+05	3.438E+06	4.688E+05	1.784E+06
Minnesota	8.779E+08	1.048E+08	2.280E+06	2.513E+06	5.393E+07	9.897E+05	5.798E+06	8.073E+05	3.063E+06
Nebraska	3.350E+08	4.048E+07	8.923E+05	9.826E+05	2.034E+07	3.382E+05	2.174E+06	3.005E+05	1.144E+06
North Dakota	1.431E+08	1.956E+07	4.143E+05	4.562E+05	8.671E+06	1.587E+05	9.189E+05	1.292E+05	4.917E+05
South Dakota	1.584E+08	2.141E+07	4.555E+05	5.011E+05	9.528E+06	1.676E+05	1.014E+06	1.401E+05	5.348E+05
Wisconsin	9.174E+08	1.199E+08	2.596E+06	2.860E+06	5.713E+07	1.003E+06	6.085E+06	8.513E+05	3.235E+06
Onroad Change in Emissions	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	-0.41%	-0.09%	0.39%	0.40%	-0.33%	2.61%	-0.86%	-0.19%	-0.26%
Iowa	-0.87%	-0.21%	0.93%	0.95%	-0.55%	6.44%	-1.90%	-0.58%	-0.63%
Kansas	-0.70%	-0.17%	0.73%	0.74%	-1.29%	4.77%	-2.54%	-1.48%	-1.49%
Minnesota	-1.07%	-0.21%	0.84%	0.86%	-1.00%	5.48%	-2.19%	-1.14%	-1.37%
Nebraska	-0.87%	-0.21%	0.92%	0.95%	-1.20%	6.36%	-2.70%	-1.34%	-1.37%
North Dakota	-1.06%	-0.20%	0.76%	0.78%	-1.31%	5.35%	-2.63%	-1.51%	-1.52%
South Dakota	-1.06%	-0.18%	0.71%	0.73%	-1.77%	5.36%	-3.18%	-2.05%	-1.70%
Wisconsin	-0.82%	-0.15%	0.60%	0.61%	-0.72%	4.21%	-1.63%	-0.83%	-0.87%

Table 2. Emissions (grams) of CO, NOx, PM, VOCs and BTEX from all **nonroad** MOVES3.0.1 sources for a July weekday in 2023.

Nonroad Base Case	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	1.751E+09	1.383E+08	1.200E+07	1.262E+07	9.953E+07	3.078E+06	9.080E+06	1.641E+06	6.068E+06
Iowa	5.270E+08	9.759E+07	8.121E+06	8.437E+06	3.674E+07	1.161E+06	3.171E+06	5.575E+05	2.043E+06
Kansas	3.968E+08	6.025E+07	4.703E+06	4.900E+06	2.574E+07	8.122E+05	2.294E+06	3.986E+05	1.466E+06
Minnesota	9.452E+08	1.276E+08	1.064E+07	1.110E+07	7.553E+07	2.345E+06	6.980E+06	1.187E+06	4.384E+06
Nebraska	2.767E+08	5.574E+07	3.903E+06	4.058E+06	2.050E+07	6.475E+05	1.806E+06	3.052E+05	1.125E+06
North Dakota	4.656E+08	1.083E+08	7.520E+06	7.780E+06	2.368E+07	8.616E+05	1.786E+06	3.128E+05	1.172E+06
South Dakota	1.607E+08	5.010E+07	3.755E+06	3.888E+06	1.315E+07	4.356E+05	1.080E+06	1.832E+05	6.669E+05
Wisconsin	8.095E+08	5.636E+07	4.721E+06	4.983E+06	6.116E+07	1.805E+06	5.813E+06	1.009E+06	3.740E+06
Nonroad 9psi Case	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	1.751E+09	1.383E+08	1.200E+07	1.262E+07	9.811E+07	3.033E+06	8.876E+06	1.617E+06	5.977E+06
Iowa	5.270E+08	9.759E+07	8.121E+06	8.437E+06	3.565E+07	1.126E+06	3.014E+06	5.387E+05	1.973E+06
Kansas	3.968E+08	6.025E+07	4.703E+06	4.900E+06	2.500E+07	7.888E+05	2.189E+06	3.860E+05	1.418E+06
Minnesota	9.452E+08	1.276E+08	1.064E+07	1.110E+07	7.262E+07	2.252E+06	6.563E+06	1.137E+06	4.197E+06
Nebraska	2.767E+08	5.574E+07	3.903E+06	4.058E+06	1.969E+07	6.218E+05	1.690E+06	2.913E+05	1.073E+06
North Dakota	4.656E+08	1.083E+08	7.520E+06	7.780E+06	2.307E+07	8.420E+05	1.698E+06	3.022E+05	1.133E+06
South Dakota	1.607E+08	5.010E+07	3.755E+06	3.888E+06	1.266E+07	4.203E+05	1.011E+06	1.749E+05	6.360E+05
Wisconsin	8.095E+08	5.636E+07	4.721E+06	4.983E+06	5.960E+07	1.755E+06	5.590E+06	9.825E+05	3.640E+06
Nonroad Change in Emissions	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	0.00%	0.00%	0.00%	0.00%	-1.43%	-1.47%	-2.25%	-1.49%	-1.51%
Iowa	0.00%	0.00%	0.00%	0.00%	-2.97%	-3.00%	-4.93%	-3.37%	-3.43%
Kansas	0.00%	0.00%	0.00%	0.00%	-2.86%	-2.89%	-4.60%	-3.18%	-3.22%
Minnesota	0.00%	0.00%	0.00%	0.00%	-3.85%	-3.96%	-5.98%	-4.22%	-4.26%
Nebraska	0.00%	0.00%	0.00%	0.00%	-3.93%	-3.96%	-6.39%	-4.54%	-4.60%
North Dakota	0.00%	0.00%	0.00%	0.00%	-2.59%	-2.27%	-4.92%	-3.37%	-3.36%
Ohio	0.00%	0.00%	0.00%	0.00%	-2.82%	-2.96%	-4.32%	-2.91%	-2.94%
South Dakota	0.00%	0.00%	0.00%	0.00%	-3.66%	-3.52%	-6.38%	-4.52%	-4.63%
Wisconsin	0.00%	0.00%	0.00%	0.00%	-2.55%	-2.75%	-3.85%	-2.66%	-2.68%

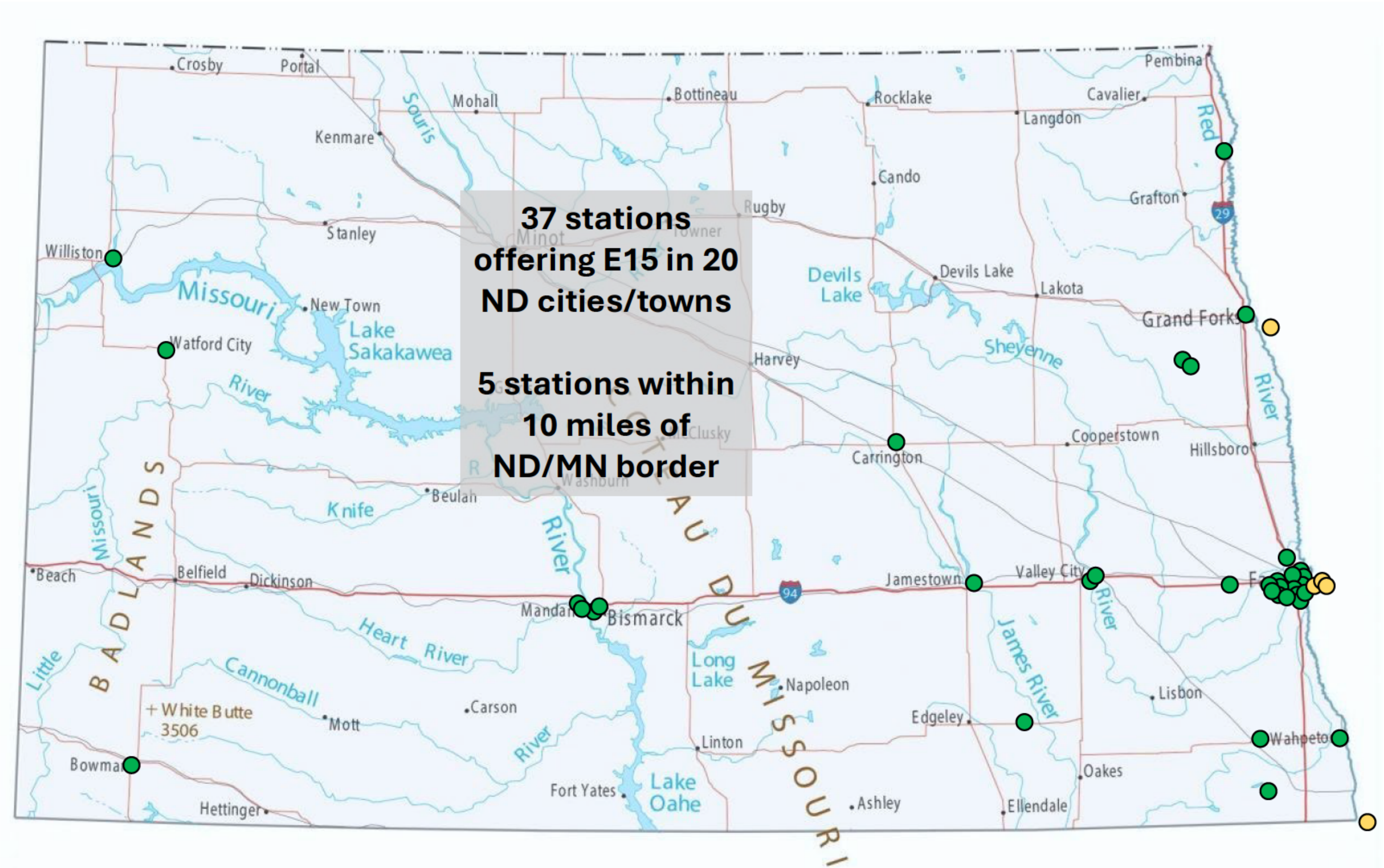
Table 3. Emissions (grams) of CO, NOx, PM, VOCs and BTEX from all **onroad and nonroad** MOVES3.0.1 sources (except brake and tire particulate emissions for onroad sources) and for a July weekday in 2023.

Onroad plus Nonroad Base Case	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	3.216E+09	3.104E+08	1.578E+07	1.678E+07	1.916E+08	4.508E+06	1.898E+07	3.002E+06	1.124E+07
Iowa	1.074E+09	1.625E+08	9.563E+06	1.003E+07	6.951E+07	1.683E+06	6.704E+06	1.045E+06	3.897E+06
Kansas	9.346E+08	1.194E+08	6.008E+06	6.337E+06	5.812E+07	1.317E+06	5.822E+06	8.745E+05	3.277E+06
Minnesota	1.833E+09	2.326E+08	1.291E+07	1.359E+07	1.300E+08	3.283E+06	1.291E+07	2.004E+06	7.489E+06
Nebraska	6.147E+08	9.631E+07	4.787E+06	5.031E+06	4.109E+07	9.654E+05	4.040E+06	6.097E+05	2.284E+06
North Dakota	6.102E+08	1.279E+08	7.931E+06	8.233E+06	3.247E+07	1.012E+06	2.730E+06	4.440E+05	1.671E+06
South Dakota	3.207E+08	7.155E+07	4.208E+06	4.385E+06	2.284E+07	5.947E+05	2.127E+06	3.262E+05	1.211E+06
Wisconsin	1.734E+09	1.764E+08	7.303E+06	7.826E+06	1.187E+08	2.768E+06	1.200E+07	1.868E+06	7.004E+06
Onroad plus Nonroad 9psi Case	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	3.210E+09	3.103E+08	1.579E+07	1.680E+07	1.899E+08	4.499E+06	1.870E+07	2.975E+06	1.113E+07
Iowa	1.069E+09	1.623E+08	9.577E+06	1.004E+07	6.824E+07	1.681E+06	6.480E+06	1.024E+06	3.816E+06
Kansas	9.309E+08	1.193E+08	6.017E+06	6.348E+06	5.697E+07	1.318E+06	5.627E+06	8.548E+05	3.203E+06
Minnesota	1.823E+09	2.324E+08	1.292E+07	1.362E+07	1.266E+08	3.242E+06	1.236E+07	1.945E+06	7.259E+06
Nebraska	6.117E+08	9.622E+07	4.796E+06	5.041E+06	4.004E+07	9.600E+05	3.864E+06	5.918E+05	2.216E+06
North Dakota	6.087E+08	1.279E+08	7.934E+06	8.236E+06	3.174E+07	1.001E+06	2.617E+06	4.315E+05	1.624E+06
South Dakota	3.190E+08	7.151E+07	4.211E+06	4.389E+06	2.219E+07	5.879E+05	2.025E+06	3.150E+05	1.171E+06
Wisconsin	1.727E+09	1.763E+08	7.318E+06	7.843E+06	1.167E+08	2.759E+06	1.167E+07	1.834E+06	6.876E+06
Onroad plus Nonroad Change in Emissions	CO	NOx	PM2.5	PM10	VOCs	Benzene	Toluene	Ethylbenzene	Xylene
Illinois	-0.19%	-0.05%	0.09%	0.10%	-0.9%	-0.2%	-1.5%	-0.9%	-0.9%
Iowa	-0.44%	-0.09%	0.14%	0.15%	-1.8%	-0.1%	-3.3%	-2.1%	-2.1%
Kansas	-0.40%	-0.09%	0.16%	0.17%	-2.0%	0.0%	-3.3%	-2.3%	-2.3%
Minnesota	-0.52%	-0.09%	0.15%	0.16%	-2.7%	-1.3%	-4.2%	-3.0%	-3.1%
Nebraska	-0.48%	-0.09%	0.17%	0.18%	-2.6%	-0.6%	-4.4%	-2.9%	-3.0%
North Dakota	-0.25%	-0.03%	0.04%	0.04%	-2.2%	-1.1%	-4.1%	-2.8%	-2.8%
South Dakota	-0.53%	-0.06%	0.08%	0.08%	-2.9%	-1.1%	-4.8%	-3.4%	-3.3%
Wisconsin	-0.44%	-0.10%	0.21%	0.22%	-1.7%	-0.3%	-2.7%	-1.8%	-1.8%

Securing Year-Round E15 in North Dakota

E15 in North Dakota

- **One out of every 11 North Dakota gas stations offers E15**
  - North Dakota has **425** total retail gas stations (Bureau of Labor Statistics)
  - **37** of those stations (9%) offer E15 (RFA)
  - North Dakota has the third-highest E15 density in the U.S.
  - We estimate that 1 out of every 25 gasoline gallons sold in 2023 was E15 (and growing)
- **North Dakota retailers want to add E15 at additional locations**
  - Some have recently received USDA HBIIP funding; others are applying
  - Consumer response to E15 is strong where offered
- **However, lack of year-round E15 access is a deterrent**
  - Biden EPA’s ad hoc emergency waivers are uncertain and not a long-term solution
  - Eight Midwest states have secured permanent year-round E15 access beginning in 2025



37 stations offering E15 in 20 ND cities/towns

5 stations within 10 miles of ND/MN border

Some brands selling E15 in ND

TESORO

PETRO SERVE USA
Helping America Fuel Better™

EXXON

CASH WISE®
Employee Owned

CENEX®

Holiday

Casey's™

Marathon

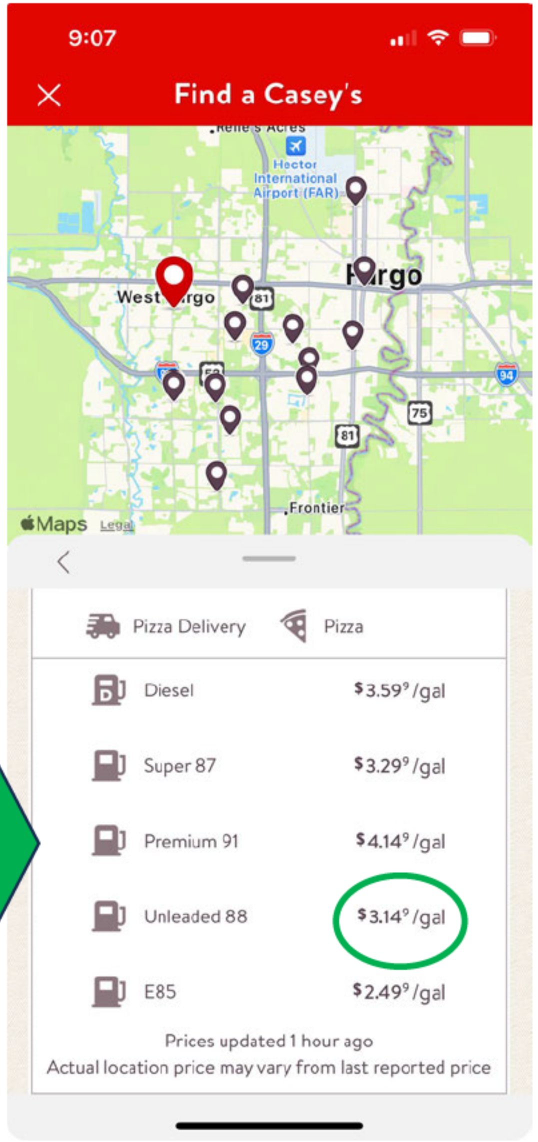
E15 Economic Benefits to ND Drivers

- ND E15 discount to E10 over past 12 months has averaged approximately **16-18 cents per gallon (5-6% discount)**
  - According to E15prices.com = 18 cents per gallon (6% savings)
  - According to Oil Price Info Service = 16 cents per gal. (5% savings)
- A typical North Dakota household that used E15 in lieu of E10 saved approximately **$180** on gasoline purchases over the past 12 months

Average ND E15 and E10 prices May-23 to May-24 (e15prices.com)

E15	**E10**
$	$
3.139	3.319

From Casey's App: E15 in West Fargo was **$0.15** less than E10 and **$1.00** less than E0 on **May 28, 2024**



Diesel	$3.59⁹/gal
Super 87	$3.29⁹/gal
Premium 91	$4.14⁹/gal
Unleaded 88	$3.14⁹/gal
E85	$2.49⁹/gal

Prices updated 1 hour ago
Actual location price may vary from last reported price

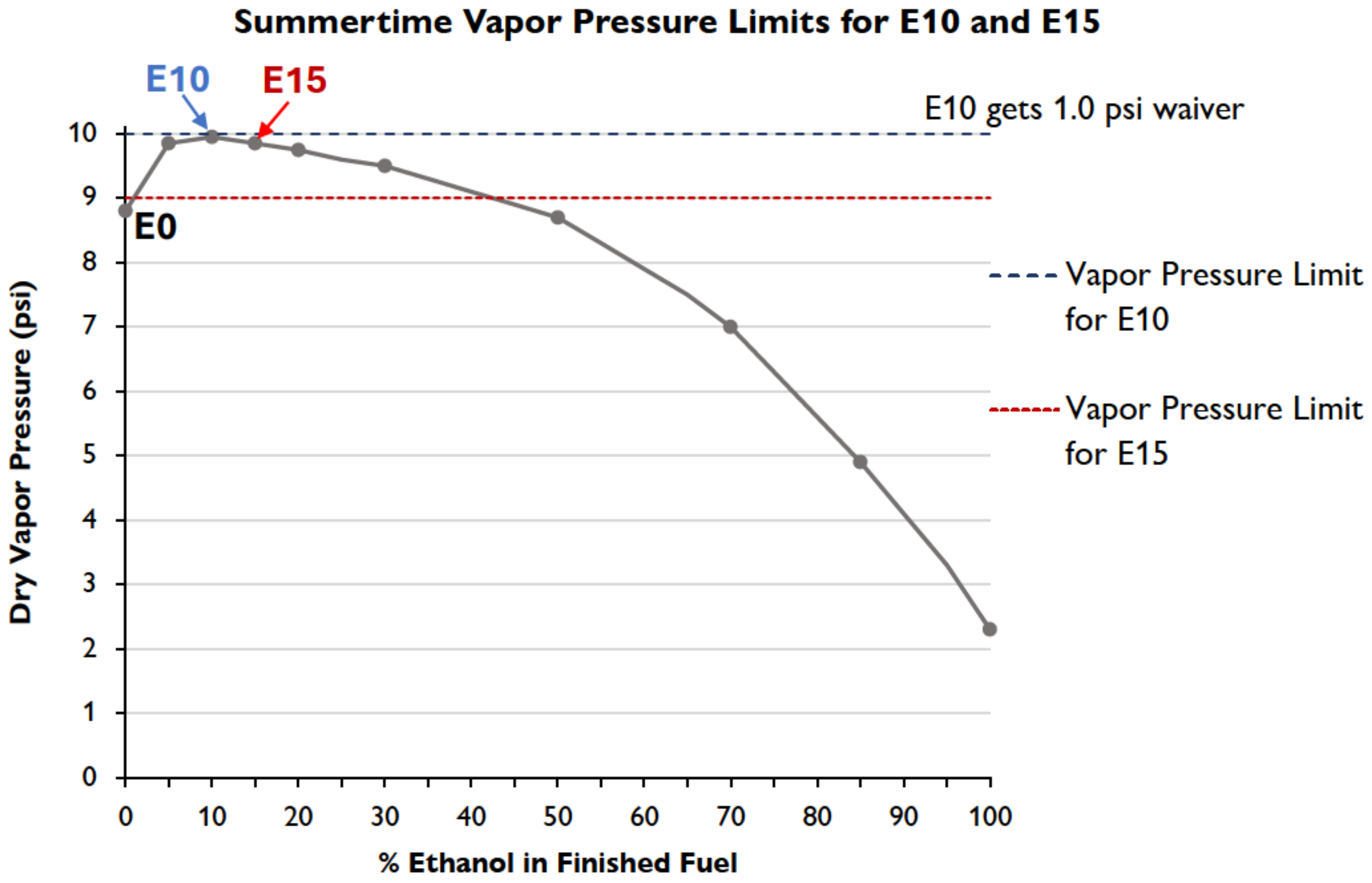
E15 Economic Benefits in 2023-2024

- ND total estimated E15 sales in 2023 =
  - 15,100,000 gallons
    - Total savings to ND consumers = $2,700,000
  - 5,500,000 gallons sold during June 1-Sep. 15 period (emergency waivers)
    - Summer savings = $990,000
- ND total projected E15 sales in 2024 =
  - 16,500,000 gallons
    - Total savings to ND consumers = $3,000,000
  - 6,050,000 gallons during June 1-Sep. 15 period (emergency waivers)
    - Summer savings = $1,089,000

E15 Economic Benefits at risk in 2025

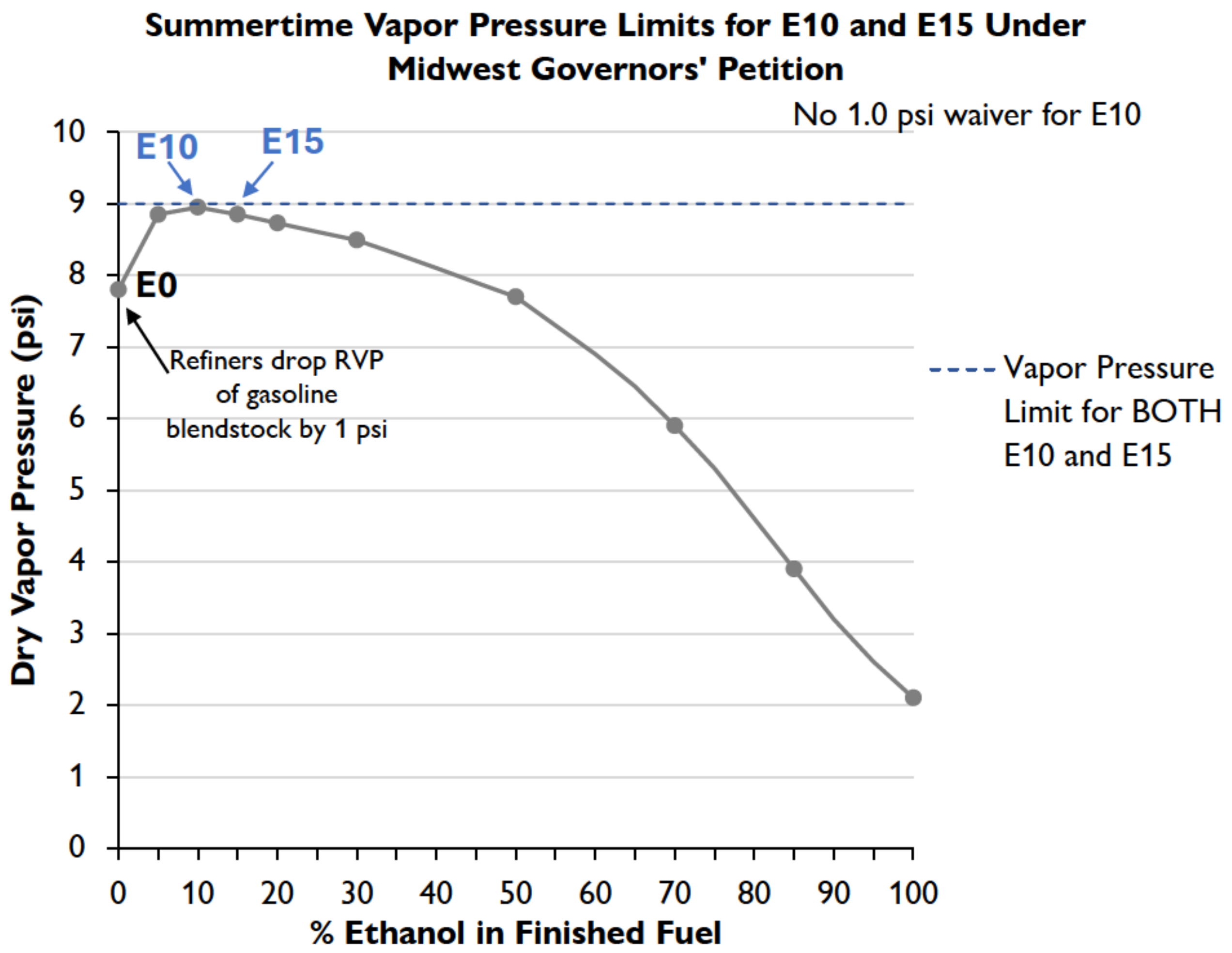
- ND total estimated E15 sales in 2025 **WITH** year-round access =
  - 18,000,000 gallons
    - Total savings to ND consumers = $3,250,000
  - 6,600,000 gallons sold during June 1-Sep. 15 period
    - Summer savings = $1,188,000
- ND total projected E15 sales in 2024 **WITHOUT** year-round access =
  - 11,400,000 gallons
    - Total savings to ND consumers = $2,050,000
  - 0 gallons during June 1-Sep. 15 period
- **Lack of year-round E15 access could cause nearly 7 million gallons of E15 demand loss in 2025 and increase ND consumer spending on gasoline by $1.2 million**

Regulatory barrier to year-round E15



- Under EPA regulations that are now 33 years old, E15 is held to a Reid vapor pressure (RVP) limit of 9.0 psi in the summertime.
- E10 is given a 1.0-psi RVP "waiver" and is held to a limit of 10.0 psi in the summertime.
- In 2019, Trump's EPA changed the regulations to allow a 10.0 psi limit for both E10 and E15.
  - ***Oil refiners sued EPA and the regulation was overturned, putting a 9.0 psi limit back in place for E15***
- Extending the 1.0-psi RVP waiver to E15 nationwide will require legislation, which has been introduced.
  - ***Some oil refiners oppose this bipartisan legislation***

Eight Midwest states found a different solution

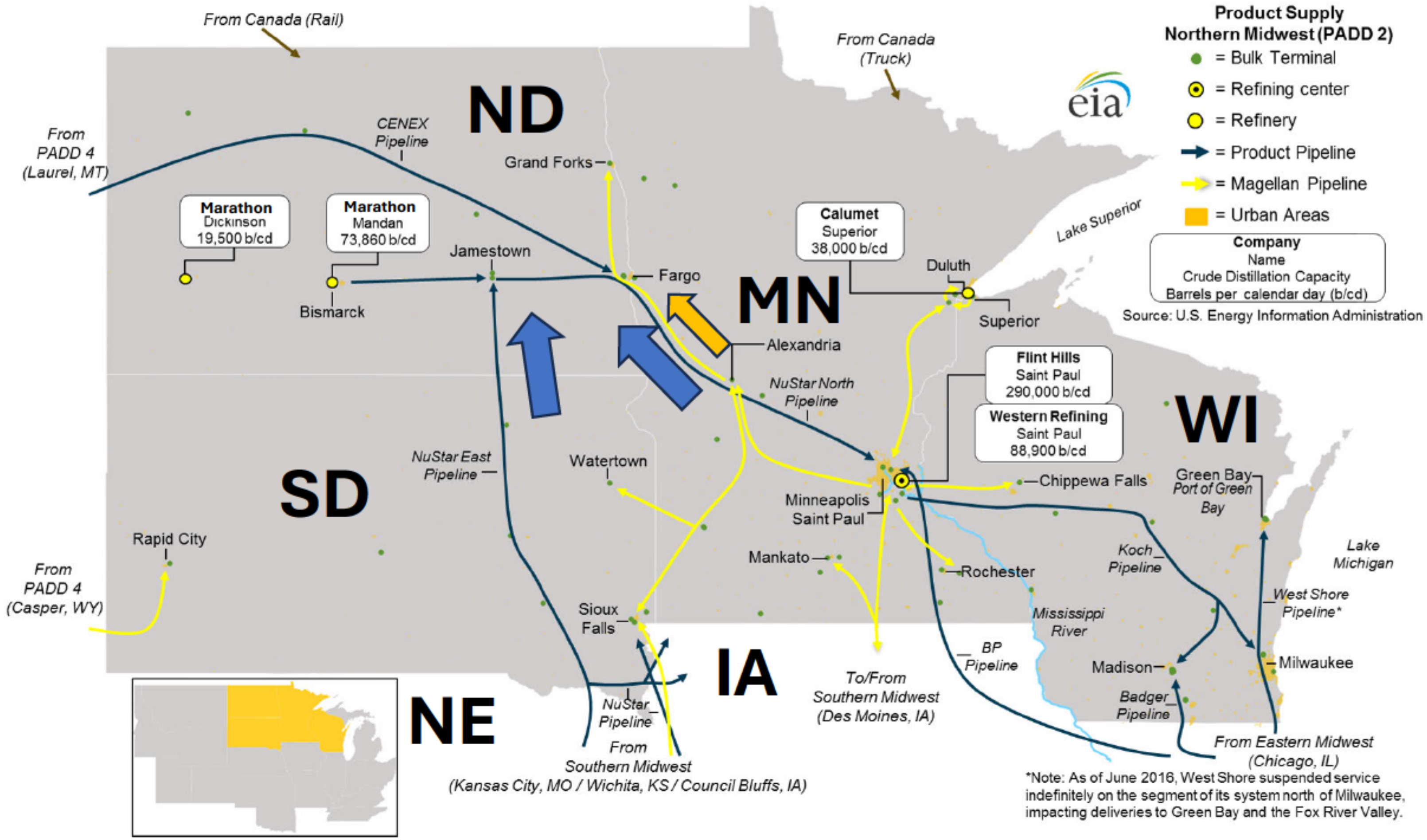


- The Clean Air Act allows Governors to petition EPA to remove the 1.0-psi RVP “waiver” for E10 in their states if such action improves air quality.
  - IA, IL, MN, MO, NE, OH, SD, WI successfully petitioned EPA to remove 1.0-psi waiver
- Removal of the 1.0-psi waiver for E10 would require E10 to meet the same summertime RVP limit as E15 (9.0 psi)
  - This would facilitate year-round sales of E15
- Thus, refiners will need to lower the RVP of gasoline blendstock from 9.0 psi to 8.0 psi.
  - ***Some refiners oppose this approach because reducing RVP could add 1-2 cents per gallon to refining costs.***

GHG Reductions from E15

- Ethanol reduces GHG emissions by approximately 50% compared to E0 gasoline.
  - Thus, E10 offers a 5% GHG reduction compared to E0 per unit of energy
  - E15 offers a 7.5% GHG reduction compared to E0 per unit of energy
- E10 has 3% less energy per gallon than E0. E15 has 4.5% less energy.
- Thus, on a per mile basis:
  - E10 reduces GHG emissions by 3.4% compared to E0
  - E15 reduces GHG emissions by **5.1%** compared to E0
- ***The 16.5 million gallons of expected ND E15 consumption in 2024 will reduce GHG emissions by more than 9,500 metric tons of CO2-equivalent***

Refining and gasoline supply logistics



Source: U.S. Energy Information Administration

*Note: As of June 2016, West Shore suspended service indefinitely on the segment of its system north of Milwaukee, impacting deliveries to Green Bay and the Fox River Valley.

- According to EIA, most gasoline blendstock in ND comes through pipeline systems that will **already be shipping lower-RVP blendstock to the eight states** who petitioned EPA.
- Refiners in adjacent states who serve ND market will **already be producing lower-RVP blendstock** to meet MN, SD, NE, IA, WI requirements.
  - Lone exception may be product shipped from Laurel, MT refinery.

From: Nowatzki, Mike G.
To: Beehler, Jace
Subject: FW: Article for NGA Newsletter
Date: Thursday, May 16, 2024 4:56:07 PM
Attachments: Outlook-14sakroc.png
ND Governor Burgum"s Leadership.docx
NGA ND workforce oped WIOA planning April 2024 draft for review.docx

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Nice letter here about the gov's remarks on urban planning. Also a reminder that we've still got that op-ed NGA penned for us. We should discuss if we still want to roll it out and what would be the best timing.

Mike

From: Rogers, Jocelyn <JRogers@nga.org>
Sent: Thursday, May 16, 2024 4:02 PM
To: Nowatzki, Mike G. <mnowatzki@nd.gov>
Subject: FW: Article for NGA Newsletter

Hi Mike – Passing this (belatedly) along in case you'd like to engage with this contact. NGA doesn't accept outside articles, but I wanted to share it for your awareness.

I hope all's well. I've also attached the workforce op-ed draft we'd discussed a few weeks ago – in case your team has any interest in moving forward. We could certainly add the news about the Bakken Area Skills Center opening.

Thanks!

From: William McPherson <wmcpherson.professional@gmail.com>
Sent: Thursday, April 25, 2024 1:50 PM
To: Rogers, Jocelyn <JRogers@nga.org>
Subject: {EXTERNAL} Article for NGA Newsletter

Joceyln,

I saw Gov. Doug Burgum's talk at the NGA winter 2024 meeting. As an Urban Planner and New Urbanist, I was inspired to see a Republican Governor from a relatively sparsely populated state with energy assets talking about smart and classically designed neighborhoods and cities. I would like to contribute an article for your newsletter. Attached is the copy. Hopefully this can help with your publication.

Best regards, Will

William McPherson
, Urban Revivalist Speaker, Podcaster
www.william-mcpherson.com
https://www.linkedin.com/in/wjmcpherson/

Color this Urban Advocate impressed. Recently, Republican North Dakota Governor Doug Burgum addressed the National Governors Association Winter Meetings in Florida regarding the adverse impacts of zoning laws in U.S. cities over the past century. Governor Burgum emphasized the need for changing of zoning laws, particularly separation of uses. The Governor is referring to Euclidean zoning, which means segregating housing, retail, government, and industrial areas. He also advocated for walkable, car-independent communities to reduce housing, infrastructure costs and proposed increasing the use of form-based code which means retail buildings and signage reflect the architectural vernacular of the community. Additionally, Governor Burgum highlighted the importance of having "third places" in the middle of neighborhoods such as coffee shops and pubs.

One of the core issues not directly addressed by Governor Burgum was the loneliness factor brought on by conventional suburban development. Having experienced life in a car-dependent community, I can attest to the impact this lifestyle manifests, including depression, anxiety and isolation. According to the American Heart Association, loneliness is a big killer in North America by increasing one’s risk of heart disease by 29% and risk of stroke by 32%. Beyond heart health, loneliness exacts expenditures on mental health medications, medical treatments such as orthopedic surgeries for a sedentary lifestyle, higher rates of property crime, and notably, incidents of road rage on the rise.

So yes, loneliness is a biproduct of the housing issues that Governor Burgum is talking about. It remains one of the most overlooked consequences of how many communities in North Dakota and most of the U.S. are set up. Suburban and rural areas often exhibit these four (4) negative consequences:

1. Insufficient Social Infrastructure: Suburban areas frequently lack the social infrastructure present in more densely populated urban regions, such as community centers, public spaces, and walkable neighborhoods. This can hinder residents from interacting and forming social bonds.
2. Isolation and Distance: Suburbs, characterized by low population density and dispersed development, can foster a sense of isolation. Residents may need to travel long distances for amenities, work, or socializing, reducing spontaneous interactions.
3. Car Dependence: Suburban living often necessitates car dependency due to limited public transportation and extensive distances between destinations. Relying on cars can diminish opportunities for casual encounters and impromptu social interactions common in urban settings.
4. Lack of Community Spaces: Many suburban neighborhoods lack communal gathering spots like parks, plazas, or cafes where people can easily meet and interact. The absence

> of these spaces diminishes opportunities for residents to connect with neighbors and build social relationships.

One of the solutions for sprawl repair is called New Urbanism. A very basic definition of New Urbanism is a planning and development approach that is based on the principles of how towns and cities were built before World War II. With Governor Burgum's foresight, the hope for the future for more human centric housing development is attainable no matter which side of the political prism one is on.

Most sincerely,

William McPherson, Urban Advocate, TEDx Speaker

Workforce op-ed draft: Governor Burgum
April 2024
774 words

North Dakota has the lowest unemployment rate in the nation. It's an enviable position to be in and a testament to our business-friendly policies and family-friendly culture. But an unemployment rate of 1.9% is not without challenges. Even with a workforce participation rate among the nation's highest, North Dakota is facing a labor shortage, with 30,000 job openings. When so many businesses can't find workers for open jobs, it impedes our economic growth.

As the most business-friendly state in the nation for two years running, according to Forbes, our challenge isn't in attracting employers. It's in recruiting, retaining and, in some cases, retraining North Dakotans to fill those jobs. And it's in attracting workers from other states.

That starts with investing in workforce infrastructure.

North Dakota is taking a comprehensive approach.

Our Workforce Development Council – which includes representatives from the private sector, labor, K-12, higher education, state and local government, and career and technical education – issued 14 recommendations to tackle the labor shortage from every angle. And my administration and the legislature got to work passing legislation to implement them.

By listening to North Dakota families, we discovered that access to child care is one of the biggest barriers jobseekers face. Last April, I was proud to sign legislation that provides nearly $66 million to support child care availability, affordability and quality. In just the first six months, more than 4,800 working families have received help with child care costs, and more than 300 child care business have benefited from grants and incentives to help them serve more families and attain quality certifications.

Expanding child care services is one of the most high-impact investments we can make in workforce infrastructure. It will make a difference for thousands of North Dakota families, increasing options for parents to pursue their goals – and for grandparents whose goal is to keep their grandkids close. It's also a selling point to out-of-state jobseekers we're recruiting through our growing Find the Good Life program.

Education and job training for all age groups is another leg of the stool. To ensure North Dakota students are prepared for jobs in our increasingly digitized world, we're equipping K-12 students with technology skills. North Dakota is the first state in the nation to approve legislation requiring cybersecurity education.

At the high school level, we're designing scholarship and apprenticeship programs to ensure that all students leave high school choice-ready for college, career or the military. Through our ND Works plan, we've expanded tools like the Technical Skills Training Grant, which since its inception in 2020 has supported the launch or expansion of nearly 30 training programs in health care, information technology, transportation, welding and more. Many of these training programs will be easily accessible in the 13 career academies we're building around the state.

These state-of-the-art facilities help students of all ages identify interests and build skills to enter the workforce – in many cases, earning while they learn and completing their training with a job offer in hand.

The success of these programs confirms every day that it doesn't take a college degree to find a good-paying job. That's even more true since Republicans and Democrats in Congress came together to pass long overdue infrastructure funding in 2021. Bipartisan policies like the Infrastructure Investment and Jobs Act and the CHIPS and Science Act are designed to launch job-creating projects in every state, ranging from roads and bridges to datacenters and facilities that manufacture products like semiconductors and electric vehicle batteries.

These projects will make America more competitive globally – modernizing our infrastructure and ensuring we stay ahead of China in the AI and microchip race. But they also fuel competition between states. There are 10 million open jobs in the United States right now. With open jobs in every state in virtually every industry, workers get can a job anywhere. To attract the workers each state needs to help alleviate labor shortages, you have to offer more than a job. You have to offer the full package – housing, child care, quality of life. In order words: workforce infrastructure.

We've laid the groundwork for success, and now it's time to build on it. Our Workforce Development Council just submitted a four-year strategic plan to the U.S. Department of Labor outlining steps to ensure North Dakota is well-positioned to capitalize on new federal investments and align our training options with opportunities.

North Dakota is on the right track, and workers outside the state are starting to notice. Let's stay focused on building the workforce infrastructure we need to reach our full economic potential and to show jobseekers what North Dakotans already know: The good life starts here.

Sources:

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From: Kari Sayler
To: Dave Goodin; joburdick1135@gmail.com; jim.hambrick@cornerstonebanks.net; Scott Heck; joe.heilman.mobile@gmail.com; a_travnicek@hotmail.com; Mike Vipond; Bahe, Becky; Beehler, Jace; Shannon Full; Pam Gulleson; Kramer, Brenda; Tiffany Lawrence; Montplaisir, Lisa; Ron Ness; Andrea Pfennig; Ralston Howe, Katherine E.; Mike Schwab; Swiontek, Steve; Zach Weis; Wobbema, Michael
Cc: John Glover; Cook, David; Boyer, Jeffrey; Leinen, Seinquis; Bertolini, David; kathryn.kloby@ndsu.edu; Kayla Effertz Kleven; Clare Carlson ; Alyssa Teubner
Subject: Agenda & Material for 4/19/24 Industry and Workforce Ad Hoc Committee Meeting
Date: Tuesday, April 16, 2024 5:01:28 PM
Attachments: image001.png
Combined Materials.pdf

Good afternoon,

The material for the Industry and Workforce Ad Hoc Committee meeting on Friday, April 19, at 11 a.m. CT is attached. This meeting will be held virtually with the instructions below.

Virtual Instructions
Join Zoom Meeting
https://us06web.zoom.us/j/89067493297?pwd=aZ59Q5Ao0xVbkNaGbAKCSj6fYnxP2T.1

Meeting ID: 890 6749 3297
Passcode: 796680

Dial by your location
+1 720 707 2699 US (Denver)
+1 253 205 0468 US
+1 253 215 8782 US (Tacoma)
+1 346 248 7799 US (Houston)
+1 669 444 9171 US
+1 719 359 4580 US
+1 646 931 3860 US
+1 689 278 1000 US
+1 301 715 8592 US (Washington DC)
+1 305 224 1968 US
+1 309 205 3325 US
+1 312 626 6799 US (Chicago)
+1 360 209 5623 US
+1 386 347 5053 US
+1 507 473 4847 US
+1 564 217 2000 US
+1 646 558 8656 US (New York)

Thanks,

Kari

Kari Sayler, '04
Senior Executive Manager
McGovern Alumni Center
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P.O. Box 5144 // Fargo, ND 58105
p: 701.231.6841 // f: 701.231.6801
tf: 800.279.8971
kari.sayler@ndsufoundation.com

NDSU | FOUNDATION

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p: 701.231.6800 | f: 701.231.6801
www.ndsufoundation.com

North Dakota State University Foundation
Industry and Workforce Ad Hoc Committee
Regular Meeting Notice and Agenda

April 19, 2024

The NDSU Foundation Industry and Workforce Ad Hoc Committee will meet on Friday, April 19, 2024, at 11 a.m. CT. This meeting will be held virtually with all members participating by video conference. The public can access the meeting using the virtual meeting instructions listed below.

#Action required *See supporting document

I.	Roll Call	
II.	Call to Order	Dave Goodin
III.	#*Approve Minutes from 3/21/24 Meeting	Dave Goodin
IV.	Opening Comments	Dave Goodin/ Dave Cook
V.	*Review Draft Recommendations	Dave Goodin
VI.	#Consider Draft Recommendations as Final Recommendations	Dave Goodin
VII.	Next Steps	Dave Goodin/ Dave Cook
VIII.	Other Business	
IX.	Adjourn	

Industry and Workforce Ad Hoc Committee Members

NDSU Foundation Trustees:
Dave Goodin, Chair
Jo Burdick
Jim Hambrick
Scott Heck
Joe Heilman
Andrea Travnicek
Mike Vipond

At-Large Members:
Becky Bahe - NDSU, Director of Career and Advising Center
Jace Beehler – Governor's Office
Shannon Full – President/CEO, FMWF Chamber of Commerce
Pam Gulleson – Member of State Board of Agricultural Research & Education
Brekka Kramer – President/CEO, Minot Area Chamber EDC
Tiffany Lawrence – President, Sanford Fargo
Lisa Montplaisir – NDSU, Professor, Biological Sciences
Ron Ness – President, North Dakota Petroleum Council
Andrea Pfennig – Director Government Affairs, Greater ND Chamber
Katie Ralston Howe – Director, ND Department of Commerce Workforce Division
Mike Schwab – Executive Vice President, ND Pharmacists Association
Representative Steve Swiontek – North Dakota Legislative Assembly
Zac Weis – Government Relations, Marathon Oil
Senator Mike Wobbema – North Dakota Legislative Assembly

Virtual Meeting Instructions:
Join Zoom Meeting
https://us06web.zoom.us/j/89067493297?pwd=aZ59Q5Ao0xVbkNaGbAKCSj6fYnxP2T.1

Meeting ID: 890 6749 3297
Passcode: 796680

Dial by your location
+1 720 707 2699 US (Denver)
+1 253 205 0468 US
+1 253 215 8782 US (Tacoma)
+1 346 248 7799 US (Houston)
+1 669 444 9171 US
+1 719 359 4580 US
+1 646 931 3860 US
+1 689 278 1000 US
+1 301 715 8592 US (Washington DC)
+1 305 224 1968 US
+1 309 205 3325 US
+1 312 626 6799 US (Chicago)
+1 360 209 5623 US
+1 386 347 5053 US
+1 507 473 4847 US
+1 564 217 2000 US
+1 646 558 8656 US (New York)

Contact Kari Sayler at 701-231-6841 or kari.sayler@ndsufoundation.com prior to the meeting date with questions or to request auxiliary aids or services if needed.

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North Dakota State University Foundation
Industry and Workforce Ad Hoc Committee
Regular Meeting Minutes
March 21, 2024

The NDSU Foundation Industry and Workforce Ad Hoc Committee met on Thursday, March 21, 2024, at 9 a.m. CT via video conference.

INDUSTRY AND WORKFORCE AD HOC COMMITTEE MEMBERS PRESENT:
Foundation Trustees: Dave Goodin, Jo Burdick, Scott Heck, Joe Heilman, Mike Vipond
At-Large Members: Becky Bahe, Jace Beehler, Pam Gulleson, Brekka Kramer, Tiffany Lawrence, Lisa Montplaisir, Ron Ness, Mike Schwab, Representative Steve Swiontek, Zac Weis, Senator Mike Wobbema

INDUSTRY AND WORKFORCE AD HOC COMMITTEE MEMBERS ABSENT:
Foundation Trustees: Jim Hambrick, Andrea Travnicek
At-Large Members: Shannon Full, Andrea Pfennig, Katie Ralston Howe

OTHERS PRESENT:
Dave Cook, Jeff Boyer, David Bertolini, Seinquis Leinen, Kathryn Kloby, Kayla Effertz Kleven, Clare Carlson

STAFF PRESENT:
John Glover, Kari Sayler, Alyssa Teubner

The Chair of the NDSU Foundation Industry and Workforce Ad Hoc Committee requested a roll call be taken for the purpose of establishing a quorum.

CALL TO ORDER: Chair Goodin called the meeting to order at 9:04 a.m.

APPROVE MINUTES FROM 1/18/24 MEETING: A motion to approve the minutes of the 1/18/24 Industry and Workforce Ad Hoc Committee meeting was made by Vipond, seconded by Swiontek, and carried unanimously.

APPROVE MINUTES FROM 2/15/24 MEETING: A motion to approve the minutes of the 2/15/24 Industry and Workforce Ad Hoc Committee meeting was made by Wobbema, seconded by Bahe, and carried unanimously.

OPENING COMMENTS: Cook shared a presentation he recently gave to the North Dakota Legislative Management Budget committee showing NDSU's response to regional recruitment strategies. The committee provided observations and feedback on the presentation.

DISCUSS AND REVIEW SURVEY DATA: Boyer reviewed the results from the committee's survey on internal priorities.

OUT OF STATE RECRUITMENT INCENTIVES: The committee discussed recruitment incentives and the need to devise a program that is unique and sustainable while considering the roles of the University, industry, and alumni.

OTHER BUSINESS: Goodin set the committee's next meeting for April 18, 2024.

ADJOURNMENT: With no further business, the meeting was adjourned at 11:02 a.m.

Respectfully submitted,
Kari Sayler, Executive Manager

INDUSTRY AND WORKFORCE AD HOC COMMITTEE
DRAFT POLICY AND OPERATIONAL RECOMMENDATIONS TO NDSU

Charge to the Committee:
The Industry and Workforce Ad Hoc Committee is responsible for providing input and proposing solutions to informing North Dakota State University's comprehensive and innovative approach to serve the state's future workforce challenges. The committee shall discuss workforce/job openings needs and trends; student and employee recruitment efforts; how NDSU can play a role in retraining existing workforce employees; and review curriculum offerings in alignment with needs of employers. The committee shall propose policy changes or funding opportunities for NDSU to pursue with State Board of Higher Education, North Dakota University System, North Dakota Legislative Assembly, Executive branch, or private benefactors. Initially, the committee shall target May 2024 as a deadline for the development of proposals and/or solutions.

Timeline:
The committee met 7 times between October 2023-April 2024.

Membership:
Chaired by Dave Goodin, recently retired President and CEO of MDU Resources. Included 23 industry leaders, elected officials, state agency representatives, and NDSU administrators.

Guiding Principles:
All recommendations have been guided with the requirement of public/private partnerships. These recommendations recognize that collaboration between the private sector and higher education is imperative for sustainable progress.

Key Focus Areas:
- Recruiting high school and non-traditional students to align with future workforce needs of North Dakota
- Retaining college students, while they are in school, by engaging them in ND workforce opportunities
- Hiring/Employing college students and college graduates to join the North Dakota workforce

I. POLICY RECOMMENDATIONS TO NDSU

The following reflect priorities and recommendations to enhance policies to help NDSU better align with industry and workforce needs of North Dakota.

LEGISLATIVE RECOMMENDATIONS
1. Increase funding and expand the North Dakota Higher Education Challenge Grant program directed to recruit new students.
2. Create a permanent endowment for the Challenge Grant Fund.
3. Increase funding and expand Operation Intern.

STATE BOARD OF HIGHER EDUCATION RECOMMENDATIONS
1. Support K-12 pathway programs in high demand areas by authorizing Dual Credit to be offered at NDSU; providing school choice for all students and their families.

2. Authorize NDSU to offer bachelor's degrees when there are workforce needs (ie. Elementary education) and associate degrees where unique institutional expertise (ie. pharmacy technicians, precision agriculture, RN-BSN, etc.) aligns with high demand workforce needs.

STAKEHOLDER RECOMMENDATIONS

1. Partner with private and public workforce recruitment efforts to combine student visa and work visa experiences. Identify a process that can be replicated for a joint school and work experience. (Department of Commerce Office of Legal Immigration)

II. OPERATIONAL RECOMMENDATIONS TO NDSU

The following reflect priorities and recommendations to enhance NDSU operations to better align with industry and workforce needs of North Dakota. Many of the recommendations below are underway, sparked by feedback and discussions by the Industry and Workforce Ad Hoc Committee over the past 6 months.

CONTINUE NDSU TRANSFORM STRATEGIC PLAN

- *Reduce -> Disrupt -> Transform -> Continuous Improvement:*
- Appropriated Budget Reductions:
  - FY23-FY24: $15M ($3.6M re-invested) (6% reduction)
  - Forecasted through FY25: $24M (13% reduction)
- Appropriated FTE Reductions:
  - FY23-FY24: 60 FTE (4.8% overall reduction; 7.5% of faculty)
  - Forecasted through FY25: 71 (5.8% overall reduction; 9.5% of faculty)
- Reduced academic colleges from 7 to 5, eliminated 2 dean positions
- Closed or consolidated 29 high cost, low-enrolled programs
- New academic program launches:
  - By Fall 24: 11 new high-demand programs to meet workforce needs
  - By Fall 25: 6 additional high demand programs to meet workforce needs
- Launched new P&L budget model.
- Investments in retention strategies:
  - New professional advising model
  - New learning assistants' model
- Ongoing continuous improvement

INCREASE INDUSTRY ENGAGEMENT ACROSS ACADEMIC ENTERPRISE

- Increase Internships;
  - Create goals for required academic internship by program.
  - Goal: 80% of academic programs have a required internship program.
- Increase experiential learning;
  - Create goals for required experiential learning by program.
  - Goal: 80% of academic programs have a required experiential learning.
- Increase industry mentoring opportunities for students.
- Enhance Welcome Week by connecting students to community and employers.
- Re-imagine campus tours for prospective students and their families to emphasize industry and workforce opportunities. Engage industry leaders participate.
- Explore opportunities for apprenticeship models in select fields.
- Review 1st and 2nd year curriculum to align with industry need.
- Enhance academic advisory boards in high demand fields with industry representatives.

- Increase industry lecturers.
- Greater emphasis on 4-year graduation, job placement, and careers in North Dakota

LAUNCHING NEW STRATEGIC ENROLLMENT MANAGEMENT PLAN

- *Developing a metric/data-driven SEM culture embracing continuous improvement through 5 strategic goals:*
    1. Grow enrollment by increasing access
    2. Provide clear pathways to a degree
    3. Maintain affordability of a degree
    4. Engage all faculty/staff in helping all prospective and current students succeed
    5. Convey distinctiveness of the student experience to differentiate NDSU

LAUNCHING NEW STRATEGIC MARKETING PLAN (SMP)

- *Developing a metric/data-driven SMP embracing continuous improvement with an emphasis on strategic enrollment management, brand management and differentiation, strategic communications, website and social media redeployment and marketing. Examples of work include:*
    - Building a stronger brand position as a solution to ND workforce challenges.
    - Building a data-driven strategic marketing plan to emphasize 4-year graduation, job placement and careers in North Dakota.
    - Establishing and report job placements by college
    - Example: 96% of graduates are placed in Engineering. 36% of MN students are working in North Dakota. 71% of North Dakota graduates are working in North Dakota

LAUNCH CORPORATE RELATIONS PROGRAM

1. Launch NDSU Foundation Corporate Relations Program which integrates all University engagement with the corporate sector.
2. Facilitates engagement with industry and community partners between these entities:
    a. NDSU academic colleges and academic departments
    b. NDSU Career Services
    c. NDSU Office of Admissions
    d. NDSU Student Affairs
    e. NDSU University Relations
    f. NDSU Research & Tech Park
    g. NDSU Athletics

LAUNCH EMERGING ALUMNI PROGRAM

1. Launch Emerging Alumni Program that focuses on creating connections between emerging alumni (ages 50 and younger), prospective students and transfer students.
2. Facilitates engagement with industry and community partners between these entities:
    a. NDSU academic colleges and academic departments
    b. NDSU Career Services
    c. NDSU Student Affairs
    d. NDSU Athletics

WORK MORE INTENTIONALLY WITH THE INDUSTRIAL COMMISSION

- Identify opportunities for NDSU to leverage talent and assets with the Industrial Commission.

REDUCE WAIVERS

- Reduce the number of waivers provided without industry involvement
    i. Example: All waivers awarded have a documented industry connection by Fall 2025.

From: Eric Delzer
To: Reiten, John R.; Brady Pelton; Ron Ness
Cc: Norrell, Ryan; Beehler, Jace
Subject: Re: WEC Comments
Date: Thursday, March 28, 2024 12:08:42 PM
Attachments: Outlook-xjiwzean.png
NDPC Waste Emission Charge Official Comments.pdf
2024 03 26 Industry Trades WEC Comments_EPA-HQ-OAR-2023-0434_FINAL_FULL.pdf
AXPC WEC Comment Letter_Final.pdf
2024 IPAA Comments on Inflation Reduction Act - WEC Proposal - March 26.pdf w Appendices.pdf

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Thanks for sharing John. Here are the comments from the industry.

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Thursday, March 28, 2024 11:01 AM
To: Brady Pelton <bpelton@ndoil.org>; Eric Delzer <edelzer@ndoil.org>; Ron Ness <ronness@ndoil.org>
Cc: Norrell, Ryan <ryan.norrell@nd.gov>; Beehler, Jace <jabeehler@nd.gov>
Subject: WEC Comments

Attached are ND's comments.

Have a great Easter weekend!

John Reiten
Senior Policy Advisor
Office of Governor Doug Burgum
Email: jreiten@nd.gov
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NORTH DAKOTA
PETROLEUM
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March 26, 2024

U.S. Environmental Protection Agency
EPA Docket Center
Air and Radiation Docket
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

RE: Waste Emissions Charge Proposed Rules Official Comments- Docket ID No. EPA–HQ–OAR–2023–0434 (Submitted Electronically at Federal eRulemaking Portal. https:// www.regulations.gov)

The North Dakota Petroleum Council (NDPC) is grateful for the opportunity to provide input on the proposed implementation of the Waste Emissions Charge (WEC) as part of the Methane Emissions Reduction Program (MERP) that was mandated by Congress under the Inflation Reduction Act (IRA). Established in 1952, the NDPC is a trade association that represents more than 550 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipelines, transportation, mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky Mountain Region. NDPC members have a vested interest in making this program a workable structure that they can operate under while continuing to provide the energy security on which the nation relies.

Background

The oil and gas industry is an integral part of the U.S. economy, and environmental stewardship is a priority of our members. In 2022, oil and natural gas accounted for 72.5% of the energy consumption in the U.S. (Source: U.S. EIA), an increase of 5% since 2021 (68.5%)[1]. The oil and gas industry has further led the way by decreasing total emissions by nearly 66% across seven major producing regions since 2011, while natural gas production increased by 179% (Figure 01).

North Dakota is ranked third in the nation in the production of oil, and NDPC's members produce 98 percent of the oil in North Dakota. Even with the remarkable growth of the Bakken Play, North Dakota's air quality remains high; there are no air quality non-attainment areas in North Dakota, and North Dakota produces approximately 3.5 million cubic feet of natural gas per day and 1.273 million barrels of oil per day. Furthermore, North Dakota has taken many steps to reduce flaring, we are currently at a 95% gas capture rate,[2] and we have decreased our methane emissions in the

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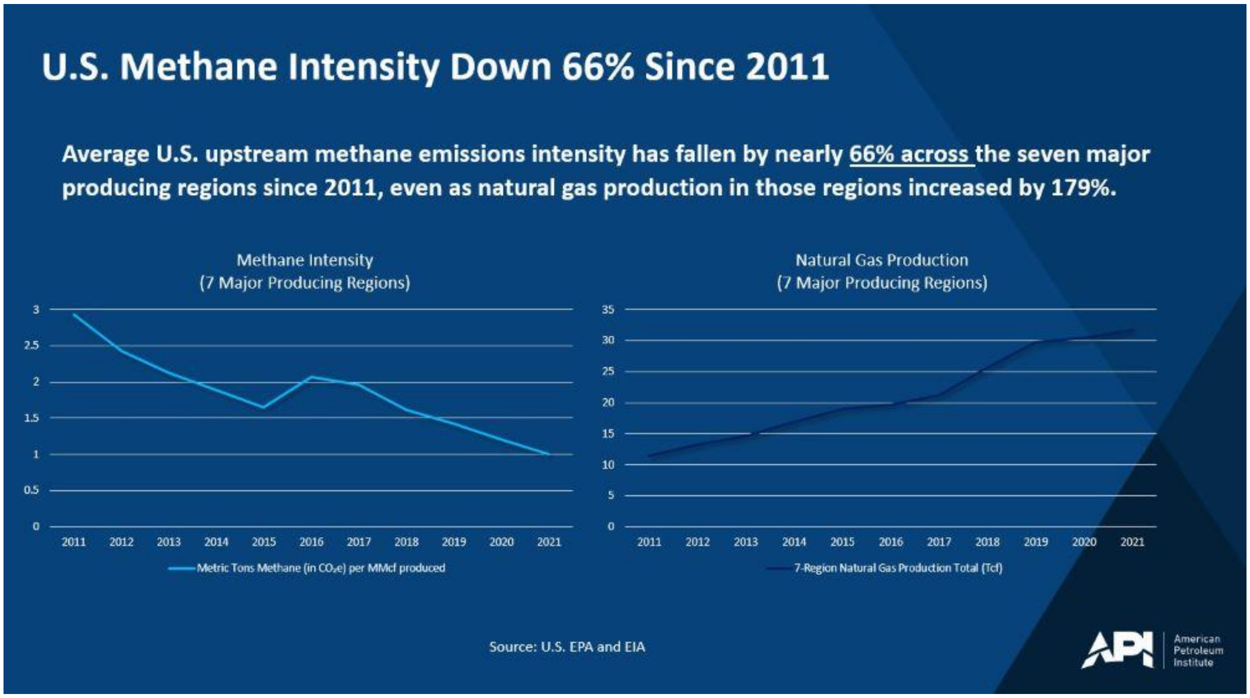
[1] U.S. Energy Information Administration. (2023, December). *U.S. Oil and Natural Gas Wells by Production Rate*. Retrieved from the U.S. Energy Information Administration website: US Oil and Gas Wells by Production Rate - U.S. Energy Information Administration (EIA)

[2] North Dakota Industrial Commission. (2023, December). Oil and Gas Production Report[1]**.** Bismarck, ND: Author.

Williston Basin by more than 30% since 2018[3]. Most recently, the NDPC worked with the North Dakota legislature to pass legislation further incentivizing a reduction in flaring through the Clean Natural Gas Capture and Emissions Reduction Program.

Figure 01



U.S. Methane Intensity Down 66% Since 2011

Average U.S. upstream methane emissions intensity has fallen by nearly 66% across the seven major producing regions since 2011, even as natural gas production in those regions increased by 179%.

Source: U.S. EPA and EIA

American Petroleum Institute

This decrease of methane emissions showcases commitment to environmental stewardship and how innovation over regulation is a superior approach to drive methane reductions. We have demonstrated, and are continuing to demonstrate, our ability to manage fossil fuels and fossil fuel-powered technologies to neutralize the climate impact of our operations. The industry is taking a proactive approach to resource development to integrate gas conservation and commercialization – maximizing gas capture and minimizing emissions. By capturing these emissions, we provide more natural gas to the market for society's beneficial use, significantly reduce energy poverty, improve energy security, and boost the worldwide economy. Overall, our resource development provides a major net-benefit to humanity and helps power a modern world.

Our commitment to environmental stewardship and compliance is also well demonstrated and documented by the EPA. In October of 2023, the EPA Region 8 office commissioned flyover inspections of 796 facilities in the Williston Basin the day after a major blizzard which brought severe weather impacts to the entire region. Despite the extreme weather conditions immediately preceding the inspections, the EPA only found a 1% noncompliance rate regarding flares, which were addressed as soon as operators were able to dig out and safely make it to their facilities.

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[3] Independent Petroleum Association of America. (2023). Methane Emissions Decline in Top Oil and Gas Basins (2018-2022). EPA Greenhouse Gas Reporting Program.

Oil and gas development is vital to North Dakota's economy, providing substantial revenues to the state and local governments that support roads, schools, public safety, and other critical services. The oil and natural gas industry also provides billions of dollars in annual economic impact and supports thousands of jobs. Taxes from oil and gas production account for 52 percent of North Dakota's tax revenue. Since 2008, North Dakota's oil and gas production tax revenues have generated over $26 billion and have provided over $1.8 billion for education and $5.9 billion in funding for communities and infrastructure across the state. The taxes have also contributed $6.9 billion to the North Dakota Legacy Fund, which serves as a perpetual source of revenue for the state's general fund and tax relief for its citizens.

Approximately 25 percent of North Dakota's oil production occurs within the exterior boundaries of the Fort Berthold Indian Reservation (FBIR) of the MHA Nation, also referred to as the Three Affiliated Tribes. The MHA Nation and the State of North Dakota have a historic oil and gas tax revenue sharing agreement, allowing a significant share of taxes assessed against oil and natural gas produced within FBIR to flow to MHA Nation members. MHA Nation generates most of its revenue based on the volume of oil extracted from within its territories, with oil and gas royalties and tax revenues constituting 80 percent of the Nation's budget.[4] This revenue is used to provide healthcare, housing, child care, elder care, as well as many other social services to Tribal communities.

Accordingly, the NDPC is very concerned about the details of the proposed WEC rule as written and how the implementation of said program may have severe negative repercussions on the industry, state and tribal economies, and the greater energy security of the country. The WEC is one of several broad and overreaching regulatory reforms being implemented that appears to ignore the disproportionately negative impacts on small independent producers and disadvantaged communities.

This proposed action may force producers to plug and abandon wells before the end of their useful life. That would have a direct negative economic impact on all North Dakotans, including Tribal members, due to decreases in royalties and declining economic activity from impacted oil and gas production. Over-regulation of the oil and gas industry increases production costs and discourages investment in the industry with little, if any, environmental benefit. Any increases in production and compliance costs will likely be passed on to the consumer, driving up the price of energy at a time when demand is rapidly increasing. This would lead to higher electricity, heating fuels, food, and transportation prices, which disproportionately impacts low-income Americans. As inflation has increased, we have seen tangible evidence of this over the last few years.

Many North Dakota mineral lessees are small businesses that run wells with little room for unplanned changes or increased operating costs from taxes or production fees that would render their wells uneconomical. Even though these wells are considered small producers, they make up a large portion of the wells in North Dakota and across the nation. The lessees may now be faced with a choice to continue their livelihood at great expense that may never be recovered or abandon those

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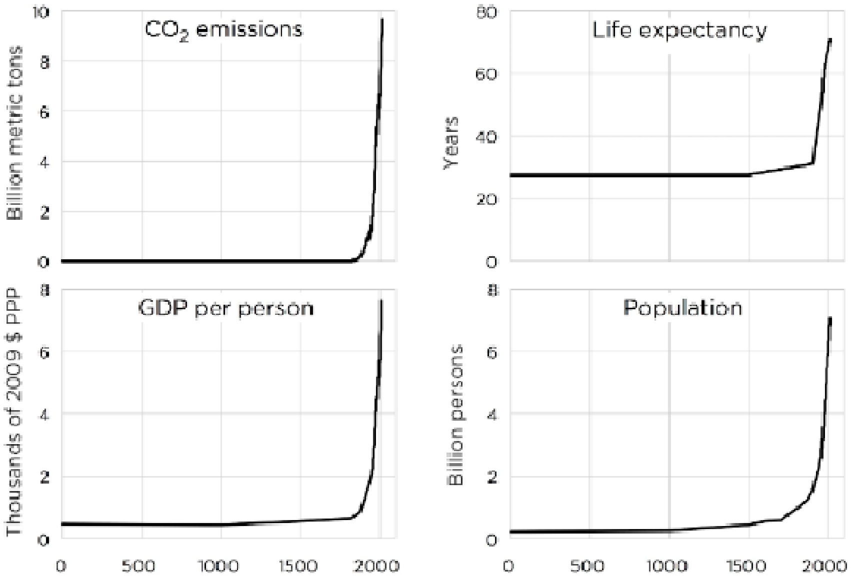
[4] Declaration of Mark N. Fox, Chairman of the Mandan, Hidatsa & Arikara Nation, also known as the Three Affiliated Tribes at 2-3, Standing Rock Sioux Tribe v. U.S. Army Corps of Eng'rs, No. 1:16-cv-01534-JEB (D.D.D. Apr. 19, 2021).

locations. The loss of this production not only impacts the energy security of the nation but the economic security of thousands of North Dakotans who depend on the royalties generated from these wells. These small producers all support other small service businesses that may also be forced into uncertain economic situations.

Recently, a letter submitted to the Council on Environmental Quality by eleven members of Congress highlighted that "Energy consumption, GDP, and life expectancy are intrinsically tied (Figure 02). Adults living at or below the poverty level are five times more likely to report poor or fair health than those living with incomes above 400 percent of the federal poverty level."[5] The Congressional letter further reported that "in 2020, 34 million U.S. households (27 percent of all U.S. households) reported difficulty paying energy bills or reported that they had kept their home at an unsafe temperature because of energy cost concerns. More than one third of Americans say they reduced or skipped basic expenses, such as medicine or food, to pay an energy bill in 2022, and the cost for an average household rose approximately $10,000 in the first two years after President Biden took office. Instead of relying on government subsidies to offset high energy costs, we should be focusing on policies that encourage more U.S. energy production and reduce the cost of energy for all Americans."

Figure 02



North Dakota has a population of approximately 779,261, and the per capita income in the state is about $41,800, similar to the national average. The median household income is slightly lower than the national average at $71,970. Approximately 11.5 percent of the North Dakota population lives below the poverty line, close to the national rate, and many are struggling right now due to soaring inflation and increased costs of goods and services.[6]

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[5] Congressional Western Caucus. (2024). *Comments on the Council on Environmental Quality's Environmental Justice Scorecard* [Letter to Brenda Mallory, Chair, Council on Environmental Quality]. U.S. House of Representatives.

[6] *North Dakota*, CENSUSREPORTER.ORG, https://censusreporter.org/profiles/04000US38-north-dakota/ (last visited Dec. 13, 2023).

The oil and gas industry offers higher average wages compared to other sectors and has spurred the development of energy courses and training programs at various colleges and universities in the state. According to a 2021 economic impact study, almost 50,000 jobs in North Dakota are a result of the oil and gas industry with a payroll totaling $4.5 billion.[7] The industry has provided people with the opportunity to make a living wage and support themselves and their families.
The economic benefit from North Dakota oil and gas production has lifted thousands of historically poor, disadvantaged, and underserved residents of rural and Tribal communities out of poverty and has brought unmeasurable improvements to health and social care in the state. Affordable energy prices benefit all sectors of the American public, and cost-effective regulation of the energy industry only benefits human health and the environment.

In light of these very real implications, we have many concerns about the proposed language in the WEC rule. We rightly question whether the potential negative impacts of this proposed regulation outweigh the diminishing returns on emissions reduction after we have demonstrably led the world in emission reduction for decades. We hope the EPA gives due consideration to the constructive feedback we have provided regarding the current proposed WEC language in our official comments detailed in the following section.

Official Comments

Definitions

The NDPC recommends that the EPA ensure consistency and harmonization in defining key operational terms across various regulations, particularly focusing on production, boosting, and gathering facilities. It is crucial that these definitions align with those established in the NSPS OOOO, OOOOa, and now OOOOb and OOOOc, which are the primary air quality regulations governing oil and gas operations. This alignment will ensure clarity and reduce regulatory complexities for industry stakeholders.

The NDPC also raises concerns regarding the EPA's approach of aggregating emissions across all reported segments to determine if they surpass the 25,000 metric ton threshold. This methodology may lead to the imposition of emissions estimation requirements on additional sites and operating companies that are currently exempt. Such a shift will likely result in an undue administrative and operational burden on the industry.

Furthermore, the EPA's reliance on historical categorizations to justify the impacts of its regulations may be flawed, especially given the significant changes proposed in 40 CFR 98, Subpart W regarding the definition of Boosting and Gathering. These modifications could extend the scope of 'WEC Applicable Facilities,' impacting a larger segment of the industry than anticipated. The EPA

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[7] DEAN BANGSUND & NANCY HODUR, NORTH DAKOTA OIL AND GAS INDUSTRY ECONOMIC CONTRIBUTION ANALYSIS SUMMARY REPORT 4 (2022), available at https://ndpetroleumfoundation.org/wp-content/uploads/2023/03/2021-Petroleum-Economic-Contributions-Summary.pdf.

must reevaluate these impacts in light of the changes to ensure a fair and accurate assessment of the regulatory burden on the industry.

The NDPC also offers the following suggestions for amended definition language for “operator” and “owner”:

> **Operator:**
> “Operator” means the person or persons responsible for the overall operation of a stationary source.
>
> **Owner:**
> “Owner” means the person or persons who own a stationary source or part of a stationary source.

Exemptions

The NDPC has identified significant concerns with the exemptions outlined in the proposed WEC rule. In their current form, these exemptions are unworkable and fail to align with the intent of the legislation.

Under the terms of the proposal, the Regulatory Compliance Exemption would not be available for at least three years (because this is how long EPA has, in the final methane rule, allowed for states to submit their 111(d) plans and for EPA to review and approve or disapprove them) and once available, will be virtually impossible to achieve. In other words, EPA has effectively interpreted the Regulatory Compliance Exemption out of the statute.

The requirement for zero violations or non-compliance across all facilities in a basin is unattainable. Reporting a deviation is a compliance demonstration for reporting under the NSPS OOOO suite of rules. Reporting of deviations does not mean non-compliance; this is compliance. This standard does not account for minor incidents like a single leaking thief hatch or unlit pilot, which can occur even in operations striving for compliance, and reporting of such is a proper compliance mechanism. The NDPC suggests that this criterion is too stringent and does not reflect the legislation's intent to encourage proactive compliance efforts. Instead, it proposes that self-reported and corrected deviations should not automatically disqualify a facility from claiming an exemption.

The EPA's stipulation that all facilities must have implemented both NSPS OOOOb and OOOOc programs before claiming this exemption is problematic. Under 40 CFR 98, Subpart W, a 'facility' refers to an entire basin, and it is unreasonable to disqualify an entire basin for minor deviations at a single well site. The NDPC suggests a revision where exemptions should be applicable at the individual facility level rather than at the basin or sub-basin level. Furthermore, the NDPC supports the American Exploration and Production Council’s (AXPC) comments on the regulatory compliance exemption and urges the EPA to develop an approach that ensures the availability and utility of the intended exemption for regulatory compliance.

NDPC proposes that the exemption for plugged wells should include the netting of removed sources such as pneumatic valves. This proposal recognizes the totality of emissions reduction efforts. The EPA's position that only flaring emissions can be exempted in cases of delayed pipeline construction is also problematic. The cascading effect of such delays on multiple emission sources should be considered, including incremental emissions related to pipeline construction delays.

The EPA's requirement for compliance with state and local regulations to claim exemptions is also concerning. The EPA lacks jurisdiction in this matter and the 30-42 month threshold for permit approval is excessively long, fails to reflect the legislative intent, and potentially worsens emissions issues. EPA should not wait until all state or federal OOOOc plans are adopted to establish the availability of the Regulatory Compliance Exemption. A state-by-state approach is more aligned with Congressional intent than the current proposal and will ensure efficiency in the plan development process, further incentivize operators' compliance with OOOOc, and ensure more operators are eligible for the exemption. Finally, NDPC asserts that additional reporting beyond the annual NSPS OOOOb and OOOOc reports should not be necessary for demonstrating compliance. The EPA already has access to these reports and certifications, and additional reporting requirements would be redundant.

The EPA needs to use more realistic, facility-level criteria for exemptions, that consider the intent of the legislation to incentivize compliance without imposing unreasonable burdens or penalties for minor deviations. These suggested revisions would make the exemptions more attainable and reflective of the operational realities within the industry.

Subpart W

The expectation for operators to estimate their 2024 emissions based on the version of Subpart W that will be in effect in 2024 is both unreasonable and potentially unfeasible. Given that the finalized rule will significantly impact reported emissions for 2024 and is not expected to be released until August of the same year, operators are left without adequate time to establish the necessary measurement and monitoring systems to comply with the new requirements. The NDPC has already communicated the various supply chain issues and delays that would hinder timely compliance with the impending final rule. Therefore, expecting compliance with the final rule to estimate emissions at WEC Applicable Facilities for the calendar year 2024 is unrealistic. This not only poses a potential compliance issue, but could also inadvertently penalize operators for circumstances beyond their control.

The Global Warming Potential (GWP) for methane changing from 25 to 28 is equally concerning. This amendment effectively lowers the threshold for the imposition of the Methane Tax and may inadvertently categorize operations previously below the threshold as above it, subjecting them to new tax liabilities. Such a change could have considerable financial implications for operations and could lead to unexpected burdens on the industry, particularly on those operators that are not currently in a position to absorb these additional costs.

NDPC urges the EPA to reconsider these aspects of the proposed rule and suggests a more measured and practical approach that takes into account the operational realities and constraints faced by the industry. Adjustments to the implementation timeline for the new Subpart W requirements and a reevaluation of the proposed GWP change are crucial to ensure that operators can meet the regulatory expectations without undue hardship.

Energy Allocation

NDPC strongly recommends EPA amend the Facility Methane Intensity calculation to define the numerator, WEC Facility Methane Emissions, as the portion of the emissions attributable to the natural gas sent to sales or facility throughput. Without this allocation of emissions to the energy produced, the assessment of facilities' methane intensity is inherently biased - the methane associated with the total fluids (oil, NGLs) production is included in the numerator (methane associated with oil and gas production), but only the gas portion of the total sold is used in the denominator.

Applying an energy allocation basis would resolve this issue by allocating emissions based on energy of products received by the facility, where these volumes are already reported to the GHGRP through subpart W. Furthermore, NDPC supports the AXPC's comments on the Facility Methane Emissions calculation and recommends the EPA amend the calculation to define the WEC Facility Methane Emissions as the portion of the emissions attributable to the natural gas sent to sales or facility throughput.

Netting

NDPC advocates for an expanded scope of netting. Netting should not be confined solely to WEC applicable facilities but allow for the inclusion of all facilities, especially those that do not seek the "Regulatory Compliance Exclusion." Facilities eligible for exemptions should also be considered for netting. This more inclusive approach would encourage broader emissions reduction efforts beyond only the facilities that are subject to the WEC, supporting a more comprehensive environmental strategy.

Netting should be permitted at the parent company level across all segments and facilities. Such a policy would align with the intent of the IRA by enabling companies to target the most cost-effective emissions reductions throughout their operations. By restricting netting to the permit or operating company level, the rule could inadvertently discourage operators from pursuing further reductions once the WEC threshold is met. NDPC notes that certain emissions, such as those resulting from compressor engine slip, are inherently more challenging to mitigate, and a policy that limits netting to the operating company level could stifle innovation and progress in emissions reduction, and result in a plateau effect at the threshold of the WEC.

Furthermore, NDPC has concerns over the EPA's broad definition of "owner," which could potentially encompass equity interest partners. The current definition is problematic because many owners are "non-operators" and do not exercise operational control, nor do they have the capacity to directly influence emissions reductions. Imposing potential WEC liability on these non-operational owners would be incongruous with long-standing financial practices within the industry and could introduce unwarranted complexities and conflicts.

Lastly, the current proposal permits netting only within the assets under a permitted entity or subsidiary level. Such a restricted approach may lead to unintended and counterproductive actions by oil and gas operating companies rather than fostering industry-wide enhancements in emissions control. NDPC calls for a full revision of the netting provisions to incorporate these suggestions that would promote more extensive and effective emissions reductions across the oil and gas industry, in line with both legislative intent and practical industry operations.

WEC Filings and Financial Obligations

The provisions of the proposed rule need adjustments to reflect operational realities and Congressional intent. The due date for the WEC fee is set for March 1$^{, 2025}$. This timing is impractical, particularly as operators have yet to align with the finalized Subpart W rule expected later in the year. The filing due date should be shifted to November 1, 2025, followed by an additional 60 days to submit the required payment, aligning with the reasonable expectation that the EPA will have concluded its review of Subpart W filings by this later date.

Error corrections are also a point of contention with the proposed due date. NDPC requests a more reasonable timeline that permits adjustments to the prior year's emissions until November 1st of each calendar year. The responsibility for errors pertaining to acquired facilities should not carry over to a new owner, which would prevent punitive measures for issues outside a new owner's control.

NDPC challenges the notion that all owners share responsibility. Instead, we suggest that only the operating entity at the time should be accountable. This aligns with historical regulatory practices that do not require unanimous owner agreement for fees. This stance recognizes the operational transfer of control and argues for proportional responsibility up to the point of ownership transfer, rather than a blanket obligation for the entire year.

NDPC also questions the need for an annual designated representative filing. Such filings should only be triggered by changes in the designated representative, rather than as a routine annual requirement. Interest charges for late corrections, if necessary, are deemed excessive. Such charges should commence only after a revised November 1st deadline, and only if the EPA upholds its end of the agreement by providing a timely assessment.

The call for third-party audits at the cost of the industry is unnecessary. The existing filings and documentation should be sufficient to meet EPA's informational needs. Imposing third-party audits is viewed as an unnecessary financial and administrative burden on the industry.

Finally, NDPC insists on a reciprocal commitment from the EPA concerning the handling of overpayment refunds. A 45-day resolution period for the industry to correct discrepancies should be matched by a similar commitment from the EPA to process any refunds, maintaining a balanced and equitable approach. The EPA must commit to completing reviews and process refund payments promptly to best reflect a fair and timely administrative process.

Conclusion

NDPC recognizes the challenges the EPA faces in creating and implementing this WEC program. However, we are very concerned that the EPA may have overreached in its selective implementation of the MERP under the IRA and believe that the existing proposed WEC language is clearly not in line with Congressional intent. Senator Joe Manchin, who was instrumental in the crafting and passage of the IRA, provided clear insight into Congress's intentions in his June 2023 letter to EPA Administrator Regan.[8] Senator Manchin expressed that the "EPA has clearly missed the boat to implement this program in a fair manner, consistent with Congressional intent."

Senator Manchin further stated that "the statute clearly intends to exempt marginal wells and smaller producers from the fee. EPA must make it clearly understood that those entities not subject to the current Subpart W Greenhouse Gas Reporting Program are not subject to EPA fees under MERP." "The MERP mandates that EPA revise Subpart W to make it more empirically based and allow for the use of individual estimates for emissions levels based on company-specific analyses. EPA must improve the accuracy and quality of its emissions factors, and EPA must provide operators a straightforward process for using the data they have available when reporting emissions. For example, MERP fees should not be calculated using arbitrary emissions factors based on metrics like "miles of gathering pipeline" for operators who have facility-based measurements that more accurately assess actual leaks, unrealistic assumptions like constant operation of pneumatic devices, or treating all compressors as having the same degree of methane slip when operators have data showing their actual facilities are performing better. EPA should draw reasonable boundaries around the definition of individual "facilities" (such as pad site, compressor site, or reporting field) for emissions intensity calculations so that aggregations of large amounts of disparate wells and gathering lines does not lead to charging a fee on marginal facilities that Congress intended to exempt or on facilities that have minimal actual emissions. To assist individuals and small businesses engaged in energy production, EPA should provide a publicly available, easily understandable explanation of the calculation method for CO2-equivalent emissions, methane intensity, and other key calculations necessary to understand the requirements of MERP. Fee calculation methodologies should be flexible and equitable to account for the wide range of oil and gas operations. For example, an operator primarily producing natural gas will be affected differently than one primarily producing crude oil with limited amounts of associated gas."

NDPC strongly urges the EPA to reconsider the current provisions of the proposed WEC rule and amend the language to include the suggestions above to further align with clear Congressional intent. Congress intended the MERP to be a tool to incentivize further emissions reduction. It was not intended to be used as a punitive action against the industry to stifle oil and gas production; increase energy, food, and consumer good costs; further erode the health, prosperity, and well-being of communities; and compromise our national energy security.

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[8] Manchin, J. (2024). Concerns regarding selective implementation of the Inflation Reduction Act and methane emissions fees. Retrieved from https://www.manchin.senate.gov/newsroom/press-releases/manchin-urges-epa-to-improve-implementation-of-methane-emissions-reduction-program

We expect the EPA will acknowledge our constructive feedback regarding specific amendments to the provisions of the proposed rule that will make this a more workable framework under which companies can reasonably operate, and one that does not disproportionately affect small operators and North Dakota environmental justice communities.

Thank you for your consideration.

Sincerely,

Ron Ness
President
North Dakota Petroleum Council

Submitted via regulations.gov

March 26, 2024

Mr. Shaun Ragnauth
Climate Change Division
Office of Atmospheric Programs
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Attention: Docket ID EPA-HQ-OAR-2023-0434

RE: Waste Emissions Charge for Petroleum and Natural Gas Systems

Dear Mr. Ragnauth:

The American Petroleum Institute, American Exploration and Production Council, American Fuel and Petrochemical Manufacturers, Independent Petroleum Association of America, LNG Allies - The USLNG Association, Energy Workforce and Technology Council, Western States Petroleum Association, Alaska Oil and Gas Association, Kentucky Oil and Gas Association, Louisiana Mid-Continent Oil and Gas Association, Michigan Oil and Gas Association, New Mexico Oil and Gas Association, North Dakota Petroleum Council, Ohio Oil and Gas Association, The Petroleum Alliance of Oklahoma, Pennsylvania Independent Oil and Gas Association, Texas Independent Producers and Royalty Owners Association, Utah Petroleum Association, Gas and Oil Association of West Virginia, and Petroleum Association of Wyoming (collectively, the “Industry Trades”) respectfully submit the below comments on the Environmental Protection Agency’s (EPA) Proposed Rule “Waste Emissions Charge for Petroleum and Natural Gas Systems” (89 FR 5318, January 26, 2024) (“WEC”).

Reducing methane emissions is a shared priority for EPA and the oil and natural gas industry. However, the Industry Trades have significant concerns with EPA's proposed implementation of the WEC. The proposed rule fails to meet the statutory requirements and objectives set forth by Congress in the Inflation Reduction Act (IRA) Methane Emissions Reduction Program (MERP). Rather than incentivizing emissions reductions, the proposed rule would maximize fees paid under the WEC and disincentivize accelerated emissions reductions.

The Industry Trades and our members have engaged constructively with EPA on the "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems", and the "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review", and look forward to continued dialogue and engagement with EPA on the WEC to ensure the final rule reflects Congressional intent, incentivizes emissions reductions, and does not unfairly and unreasonably impose additional costs on American energy production. If you have any questions regarding the content of these comments, please contact Ryan Steadley at steadleyr@api.org.

Sincerely,

Holly Hopkins

Holly A. Hopkins

Vice President, Upstream Policy
American Petroleum Institute

cc:
Sharyn Lie, EPA Lie.Sharyn@epa.gov
Jennifer Bohman, EPA Bohman.Jennifer@epa.gov

INDUSTRY TRADES INTERESTS

The **American Petroleum Institute (API)** is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. Gross Domestic Product (GDP). API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators, and marine transporters, as well as service and supply companies, providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

The **American Exploration and Production Council (AXPC)** is a national trade association representing 30 of the largest independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of providing positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

American Fuel and Petrochemical Manufacturers (AFPM) is a national trade association whose members comprise most U.S. refining and petrochemical manufacturing capacity. AFPM is the leading trade association representing the makers of the fuels that keep us moving, the manufacturers of the petrochemicals that are the essential building blocks for modern life, and the midstream companies that get our feedstocks and products where they need to go. To receive necessary materials and to move their essential products to satisfy growing demand, AFPM members depend on the timely development of, and enhancements to, transportation infrastructure such as pipelines.

The **Independent Petroleum Association of America (IPAA)** represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, which will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The **USLNG Association**—operating under the global brand name of **LNG Allies (LNGA)**—is the only independent organization focused solely on advancing the interests of the USLNG industry. We are a 501(c)(6) nonprofit trade association. Our members include USLNG exporters and project developers, U.S. natural gas producers, and allied service companies, including engineering firms, equipment makers, and global gas infrastructure providers. As the leading industry voice, we promote effective public policy and communicate the domestic and global benefits of USLNG exports. We also conduct and sponsor research and policy analysis; organize workshops, conferences, and issue briefings; and provide information about USLNG exports. Internationally, we work to open new markets for USLNG exports, expand existing markets, and establish strategic relationships. Our mission is to help bring the climate, environmental, economic, and geostrategic benefits of USLNG to the world.

Energy Workforce and Technology Council (EWTC) is the national trade association for the energy technology and services sector, representing over 300 companies and employing more than 650,000 energy workers, manufacturers, and innovators in the energy supply chain. Energy Workforce members have employees in all 50 states. Membership ranges from large energy services companies with global operations all the way down to small family-owned well-servicing companies that operate locally within the U.S. Energy Workforce member companies provide the United States and the world with energy in the most environmentally safe, efficient, and responsible way possible, and our sector is leading the development of technology that will ensure our country maintains energy security that will power our economy and protect our way of life for generations to come. Energy Workforce members are active in multiple segments of the oil and natural gas supply chain starting with production of oil and natural gas through well servicing, drilling, well stimulation, completions, and distribution.

Western States Petroleum Association (WSPA) is a non-profit trade association that represents companies that account for the bulk of petroleum exploration, production, refining, transportation and marketing in the five western states of Arizona, California, Nevada, Oregon, and Washington. WSPA's headquarters is located in Sacramento, California. Additional WSPA locations include offices in Torrance, Concord, Ventura, Bakersfield, and Olympia, Washington. WSPA is dedicated to ensuring that Americans continue to have reliable access to petroleum and petroleum products through policies that are socially, economically and environmentally responsible. We believe the best way to achieve this goal is through a better understanding of the relevant issues by government leaders, the media and the general public. Toward that end, WSPA works to disseminate accurate information on industry issues and to provide a forum for the exchange of ideas on petroleum matters.

The **Alaska Oil and Gas Association (AOGA)** is a professional trade association whose mission is to foster the long-term viability of the oil and gas industry for the benefit of all Alaskans. We represent the majority of companies that are exploring, developing, producing, transporting, refining, or marketing oil and gas on the North Slope, in the Cook Inlet, and in the offshore areas of Alaska.

The **Kentucky Oil and Gas Association (KOGA)** represents the interests of its members who are primarily small independent producers of oil and natural gas that operate for the most part, low volume/low pressure wells across the Commonwealth of Kentucky.

The **Louisiana Mid-Continent Oil and Gas Association (LMOGA)** serves exploration and production, refining, transportation, marketing, and mid-stream companies as well as other firms in the fields of law, engineering, environment, financing, and government relations. LMOGA's mission is to promote and represent the oil and gas industry operating in Louisiana and the Gulf of Mexico by extending the representation of our members to the Louisiana Legislature, state and federal regulatory agencies, the Louisiana congressional delegation, the media, and the general public.

The **Michigan Oil And Gas Association (MOGA)** represents the exploration, drilling, production, transportation, processing and storage of crude oil and natural gas in the State of Michigan. MOGA has nearly 650 members including independent oil companies, major oil companies, the exploration arms of various utility companies, diverse service companies and individuals. Organized in 1934, MOGA monitors the pulse of the Michigan oil and gas industry as well as its political, regulatory, and legislative interest in the state and the nation's capital. MOGA is the collective voice of the petroleum industry in Michigan, speaking to the problems and issues facing the various companies involved in the state's crude oil and natural gas business.

The **New Mexico Oil and Gas Association (NMOGA)** is a coalition of oil and natural gas companies, individuals, and stakeholders dedicated to promoting the safe and environmentally responsible development of oil and natural gas resources in New Mexico. Representing over 200 member companies, NMOGA works with elected officials, community leaders, industry experts, and the general public to advocate for responsible oil and natural gas policies to increase public understanding of industry operations and contributions to the state.

Established in 1952, the **North Dakota Petroleum Council (NDPC)** is a state trade association that represents more than 600 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipelines, transportation, mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky Mountain Region; to promote opportunities for open discussion, lawful interchange of information, and education concerning the petroleum industry; to monitor and influence legislative and regulatory activities on the state and national level; and to accumulate and disseminate information concerning the petroleum industry to foster the best interests of the public and industry. Our members have a vested interest in making this program a workable structure that we can operate under while continuing to provide the energy security the nation relies on.

The **Ohio Oil and Gas Association (OOGA)** is a trade association with members representing the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio. OOGA membership is comprised of independent, major national, and major international oil and natural gas companies—all focused on the exploration, discovery, and production of crude oil, natural gas, and associated liquids in Ohio, along with companies representing all aspects of the midstream and downstream operations, including pipelines, processors, and refineries.

The **Petroleum Alliance of Oklahoma (PAO)** represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. Our members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas. Our members are committed to extracting, producing, transporting, and refining crude oil and natural gas in a safe and environmentally-sound manner. The Alliance's members have made significant strides in reducing and/or eliminating greenhouse gas (GHG) emissions and continue to pursue technologies and innovative solutions to detect, reduce and eliminate methane emissions. Our members provide abundant, clean-burning natural gas that has enabled the United States to become the global leader in greenhouse gas emissions reductions.

The **Pennsylvania Independent Oil and Gas Association (PIOGA)**, historically the principal nonprofit trade association representing Pennsylvania's independent crude oil and natural gas producers, marketers, service companies and related businesses, continues to expand its focus as it embraces the entire oil and gas spectrum, from upstream through midstream and downstream entities. As tremendous success in accessing Marcellus and Utica reserves has dramatically increased supply with a resulting sharp decline in commodity prices, PIOGA has broadened its emphasis to seek expanded markets and additional uses for natural gas and related products. This has led to an expansion of PIOGA's focus to more fully include pipeline operators and end-users such as power generation, industrial, and manufacturing consumers of methane, ethane and related commodity products. Working together, we help members accomplish that which they cannot achieve alone.

Founded in 1946, **Texas Independent Producers and Royalty Owners Association (TIPRO)** is one of the oldest and largest oil and natural gas trade associations in the state of Texas. TIPRO's nearly 3,000 members include small family-owned businesses and the largest publicly traded producers, in addition to large and small mineral estates and trusts creating a unique and impactful voice for the industry. Collectively, TIPRO members produce nearly 90 percent of the oil and natural gas in Texas and own mineral interests in millions of acres across the state.

The **Utah Petroleum Association (UPA)** is a statewide oil and gas trade association established in 1958 representing companies involved in all aspects of Utah's oil and gas industry. UPA members range from independents to major oil and natural gas companies, including upstream E&P companies, midstream operators, refineries, and a broad range of service providers. We represent nearly 90% of the crude oil production in the state and all 5 of the state's refineries. Our members are widely recognized as industry leaders responsible for driving technology advancement resulting in environmental and efficiency gains.

The **Gas and Oil Association of West Virginia (GO-WV)** is a non-profit organization that works to promote and protect all aspects of the oil and natural gas industry in West Virginia. GO-WV currently has over four hundred and fifty (450) member companies, which include independent producers, fully integrated energy companies, companies engaged in various aspects of service and supply activities, and consulting companies. The members of GO-WV operate in nearly every county of West Virginia and employ thousands of people located in the State of West Virginia.

The **Petroleum Association of Wyoming (PAW)** represents the state's oil and gas industry including production, midstream processing, pipeline transportation, and oil field service companies. The Association also represents affiliated companies offering oil and gas related legal, accounting, oilfield services, and consulting services. Eighty-five percent of the oil and gas companies operating in Wyoming are classified as small businesses.

Executive Summary

Although claiming to base the WEC Proposed Rule on a plain reading of the statutory text, EPA has in reality designed a program that countermands the plain intent of Congress and in many cases goes far beyond the enabling statute by limiting the scope of emissions netting, creating unattainable exemption criteria, and establishing an unworkable administrative timeline, among other issues described herein. To facilitate review of our comments, we have listed below our primary concerns with the Proposed Rule, with our detailed comments following the same sequence.

1) EPA's failure to adequately consider the New Source Performance Standards OOOOb/Emissions Guidelines OOOOc, Subpart W, and WEC as interconnected regulations undermines the industry and the administration's shared goal of reducing methane emissions with technically feasible and cost-effective solutions.

2) Operators should be able to net at the parent company level. Allowing netting at the parent company level is appropriate because it would fully implement Congress's clear purpose of mitigating the impact of the fee program and incentivize emission reductions across operations under the same parent company.

3) The exemption language EPA proposes is unduly restrictive across all exemption categories contemplated by Congress.

   a. EPA should adopt a case-by-case process for determining whether an unreasonable delay in permitting has occurred for the purpose of that exemption since the proposed brightline criteria for contribution to delay and defining unreasonable delay are inappropriate and impractical. The exemption should include other methane emissions that result from an unreasonable delay in environmental permitting for gathering or transmission infrastructure.

   b. The regulatory compliance exemption should be available as soon as a state or federal program is in effect for the state(s) in which the facility is located. For the purposes of the regulatory compliance exemption, "applicable facility" should be understood to mean the "affected facility" under NSPS OOOOb or state equivalent pursuant to EG OOOOc. The applicable/affected facility should be considered "in compliance" with methane emission standards unless a violation is proven through adjudication or is admitted by the owner or operator; a proven or admitted violation should disqualify only the applicable/affected facility from the exemption.

   c. EPA should expand the exemption for permanently shut-in and plugged wells to include all methane emissions from all equipment and processes that were associated with the permanently shut-in and plugged well. Recordkeeping and reporting for this exemption should not be duplicative with other existing well closure requirements.

4) EPA must establish a workable timeline between Subpart W reporting and validation and WEC filing and validation. The WEC filing should occur only when Subpart W reports have been validated to avoid an untenable cycle of additional payments or refunds.

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List of Attachments

Attachment A – Previous API Comments on NSPS OOOOb and EG OOOOc, Docket No. EPA-HQ-OAR-2021-0317

Attachment B – Previous Industry Trade Comments on Proposed Subpart W Revisions, Docket No. EPA-HQ-OAR-2023-0234

PROPOSED WASTE EMISSIONS CHARGE FOR PETROLEUM AND NATURAL GAS SYSTEMS (WEC)
DOCKET ID: EPA-HQ-OAR-2023-0434

Due to the unreasonably short duration of the comment period for this Proposed Rule, the Industry Trades have been unable to respond to all of EPA's comment solicitations. Although EPA granted a 15-day comment extension, API had requested a 30-day extension[1] given the complex nature of the proposed WEC rule and connections to EPA's proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas System ("Subpart W")[2], and EPA's proposed New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review ("Methane Rule" or "OOOObc")[3].

While every effort has been made to consider the effects of our comments, unintended consequences may still occur due to the unknown outcome of the final Subpart W revisions, which will be the basis for calculating the WEC. The following guiding principles should therefore be observed for our comments:

- Owners or Operators should have the ability to maximize netting and exemptions when calculating their WEC.
- WEC filing and payment process should be streamlined and consider Subpart W validation process.
- Interest and penalties should not be imposed on updated WEC filings and payments resulting from EPA validation of Subpart W or WEC.

Finally, due to the myriad of uses for the term "facility", we have endeavored to articulate when "facility" refers to a geographically discrete stationary source (c.f. New Source Review), an affected or designated facility under OOOObc, or a reporting facility or segment under Subpart W. We also provide comments on "facility" definition for the purposes of the WEC in Comment 7.0

1.0 Regulatory Coherence

EPA must administer the WEC in a manner that is reasonable and consistent with other related rulemakings (OOOObc and Subpart W). EPA's piecemeal regulatory actions jeopardize timely and effective WEC implementation[4,5].

1.1 EPA failed to adequately consider OOOObc, Subpart W, and WEC as interconnected regulations aiming to reduce methane emissions with technically feasible and cost-effective solutions.

The proposed WEC is statutorily connected to OOOObc and Subpart W with the overall aim of reducing methane emissions with technically feasible and cost-effective solutions. As of the date of this comment letter, OOOObc has only recently been finalized, but Subpart W has not. Despite the overlapping development of these rules (to meet rushed and impractical timelines), EPA has failed to recognize the interdependence of these complex regulations and therefore jeopardizes timely and effective implementation of the WEC. EPA must administer all

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[1] EPA-HQ-OAR-2023-0434-0140

[2] 88 FR 50282

[3] 87 FR 74702

[4] https://www.manchin.senate.gov/imo/media/doc/merp_letter_to_epa.pdf?cb

[5] https://www.epw.senate.gov/public/_cache/files/b/0/b0559828-89b1-4456-820c-51ae1ecb7315/98783E8E1057069E7FB16CBB7B32FDE3.subpart-w-letter-final-12.13.23.pdf

three of these regulations in a reasonable and coherent manner. Procedurally, EPA has not given a meaningful opportunity to comment on the proposed WEC rule since Subpart W revisions have not been finalized.

1.2 Unreasonable implementation of OOOObc would make the regulatory compliance exemption from the WEC unachievable and meaningless.

API submitted detailed comments[6] on EPA's proposed Methane Rule, which are the basis for the regulatory compliance exemption for the WEC. A copy of these comments is included as Attachment A, and key comments are summarized below.

- **Emissions detected from covers and closed vents system do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.** As proposed, a WEC applicable facility must have no deviations or violations to be eligible for the regulatory compliance exemption. An unreasonable application and interpretation of the "no identifiable emissions" standard would make the regulatory compliance exemption practically impossible to meet.
- **EPA underestimates the number of affected facilities under NSPS OOOOb, which further increases the difficulty in qualifying for the regulatory compliance exemption.** With a proposed criterion of no deviations or violations for an entire WEC applicable facility (as understood to be an entire Subpart W reporting basin), an increased number of NSPS OOOOb affected facilities would make qualifying for the exemption practically unachievable.
- **Only a proven or admitted violation, not a deviation or accusation of violation, should make an applicable/affected facility ineligible for the regulatory compliance exemption.** As discussed further in Comment 4.0, the regulatory compliance exemption should be based on no proven or admitted violations rather than deviations or mere accusations of violations.
- **The WEC exemption should be based on the OOOObc affected or designated facility basis and take into account the duration of a noncomplying event.** Compliance with OOOObc is based on an "affected or designated facility" level (i.e. the distinct equipment or collection of equipment regulated as the affected or designated facility under OOOObc, hereafter referred to only as "affected facility" for clarity and simplicity) while the WEC regulatory compliance exemption is proposed on the "WEC applicable facility" level (i.e., the collection of discrete sites with OOOObc affected facilities within a Subpart W reporting basin). The regulatory compliance exemption should also be based on the OOOObc affected facility level, which would allow operators to exempt from WEC those sites with OOOObc affected facilities that are in compliance even if other sites in the larger WEC applicable facility do not qualify for the exemption. The exemption should also incorporate the duration of a noncomplying event. For example, if a noncomplying event lasts for 24 hours, the exemption should be available for the remainder of the reporting year.
- **The WEC disincentivizes early compliance with EG OOOOc and other voluntary reduction initiatives based on proposed netting calculations.** Early adoption of EG OOOOc and other voluntary methane reduction actions may make facilities unable to net for determination of the WEC since WEC facilities less than 25,000 metric tons of CO_2e are proposed to be ineligible to participate in netting. The inability to net methane reductions from voluntary efforts may disincentivize implementation of cost-effective methane solutions before implementation of a state's respective EG OOOOc state plan. The 25,000 metric ton CO_2e

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[6] EPA-HQ-OAR-2021-0317-2428, EPA-HQ-OAR-2021-0317-3817, EPA-HQ-OAR-2021-0317-3819, EPA-HQ-OAR-2021-0317-3838, and EPA-HQ-OAR-2021-0317-3849.

threshold could therefore be treated as a "floor" for methane reduction efforts since the proposed rule does not encourage any further reductions beyond that level. Furthermore, EPA's proposed "all or nothing" approach for the regulatory compliance exemption does not accelerate EG OOOOc compliance since the exemption is unavailable until all state (or federal) plans are effective. Therefore, the Industry Trades recommend that WEC applicable facilities with less than 25,000 metric tons of CO_2e be eligible for netting and that a OOOObc applicable facility should be eligible for the regulatory compliance exemption as soon as the applicable plan is effective for the state(s) in which it is located; see Comment 2.1 and Comment 4.1, respectively.

1.3 Subpart W revisions must support efficient and accurate reporting of methane emissions as the basis for the WEC.

Subpart W is now unique among all other subparts of the GHGRP in that emissions information submitted under Subpart W will serve regulatory purposes not shared by other industries that report under other subparts. Efficient and accurate reporting of methane emissions under Subpart W would facilitate fair and accurate WEC calculations and fee amounts. API along with other trade organizations submitted detailed comments[7] concerning EPA's proposed revisions to Subpart W, which are the basis for calculating the WEC beyond 2024. This comment letter is included as Attachment B and key comments are summarized below:

- **EPA should avoid any potential double-counting or over-estimation of emissions across source types.** Double counting or over-estimation of emissions, especially through the proposed other large release event requirements and tiered approach to flare "combustion efficiency", would unfairly overestimate the WEC.
- **Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities should be reported under Subpart C and should not be included under Subpart W.** Reporting combustion emissions under Subpart W is inconsistent with how combustion is reported for all other industries under 40 CFR Part 98 and, given the interconnectedness of Subpart W with the WEC rule, such emissions cannot be considered "waste". As such, non-flaring combustion emissions should not be subject to any fees for "waste" and should be removed from Subpart W and captured in Subpart C. At a minimum, combustion emissions should not be included in the WEC fee calculation as those emissions are not a "waste". API provided a detailed comment about this issue in the comments submitted for the proposed Subpart W revisions (Attachment B).
- **Subpart W must accommodate reporting emissions based on empirical data as a demonstration of emission reductions.** As required by CAA §136(h), Subpart W reporting (and by extension WEC calculations) must allow operators to submit empirical data "to accurately reflect the total methane emissions and waste emissions from the applicable facilities". The proposed Subpart W revisions do not allow operators to use readily available empirical data to show emission reductions and differentiate company performance (e.g., engine performance tests versus a static emission factor or control efficiency). See our detailed comments on the proposed Subpart W revisions (Attachment B).
- **EPA must set a period over which submitted GHG reports are considered "final" now that reported emissions will be used as a basis for the WEC.** The continual litany of questions from EPA to operators

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[7] EPA-HQ-OAR-2023-0234-0402, EPA-HQ-OAR-2023-0234-0403, and EPA-HQ-OAR-2023-0234-0404

years after Subpart W reports have been submitted must have a defined endpoint. Many queries are administrative in nature and do not lead to a significant change in emissions. EPA must establish a clear deadline for when emissions are validated and final. We provide more detail in Comment 6.0.

1.4 EPA has underestimated the impact of the WEC by basing its analysis on RY2021 Subpart W data.

EPA has underestimated the impact of the WEC by basing its analysis on RY2021 Subpart W data. This data underestimates the impact of the proposed WEC in two respects:

- RY2021 occurred during the COVID-19 pandemic and may not accurately reflect a typical year for oil and gas operations due to reduced energy demand.
- RY2021 (or any other year) data do not reflect the proposed Subpart W revisions which, based on the proposed Subpart W rule, will significantly increase reported methane emissions.

Given the unknown outcome of the final Subpart W revisions, the Industry Trades cannot fully assess the impact of the WEC. Given previous instances where EPA underestimated the impact of its rulemakings (e.g., storage vessels under NSPS OOOO). API believes that EPA has greatly underestimated the impact of the WEC, which also results in a failure to adequately assess impact to small businesses[8].

1.5 EPA must ensure regulatory harmonization and consistency.

In light of the volume of regulatory actions addressing methane, EPA should facilitate greater intra-agency coordination to ensure that EPA's regulations are internally consistent for their own purposes, and can serve as a basis for other agencies to harmonize their requirements with EPA's. These actions include, but are not limited to:

- Treasury Department – Section 45V regulations for hydrogen production tax credit, with the treatment of differentiated natural gas
- DOT/PHMSA – LDAR Rule
- DOI/BLM – Waste Prevention Rule
- DOE/Argonne – GREET Model, used as the basis for calculating GHGs associated with hydrogen production for eligibility for the Section 45V tax credit
- DOE – Differentiated Gas Framework
- State Department – International methane MRV standard (with DOE)
- State Department – Global discussions on an EU Import standard and global methane policy

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[8] Regulatory Flexibility Act

2.0 The Proposed Netting Provisions Are Unreasonably Constrained.

A key element of CAA § 136 is the ability of an owner or operator to net facility emissions "within and across all applicable segments" when determining whether fees must be paid and, if so, the amount of the fees. CAA § 136(f)(4) plainly was intended by Congress as a program flexibility that would reduce the fees paid under the WEC program. That clear Congressional intent would be better effectuated by a broadly applicable netting rule (i.e., one that allows netting among all facilities within the applicable segments under the common ownership of a parent company). EPA's proposed approach to netting is inconsistent with CAA § 136(f)(4) and would unreasonably constrain the opportunity for netting in two ways.

2.1 Netting should be allowed at the parent company level.

EPA proposes that the owner or operator that would be allowed to net among facilities would be "the Subpart W facility 'owner' or 'operator' as reported under 40 CFR 98.4(i)(3)."[9] EPA argues that approach "aligns with a plain reading of the statutory text" because "CAA section 136(c) requires the charge to be imposed and collected on a facility owner or operator, and CAA section 136(h) presumes that owners and operators are responsible for submitting empirical data."[10] EPA further argues that, "since the list of owners or operators for each facility is directly reported under 40 CFR 98.4(i)(3), an established program at the time that Congress drafted CAA section 136, the EPA proposes that under the best reading of the statutory text, the facility owner or operator would be used as the entity for establishing common ownership or control of subpart W facilities within and across all applicable subpart W industry segments."[11] EPA asks for comment on the alternative approach of using the parent company of a facility owner or operator, although that is not EPA's preferred approach.[12]

To begin, while Subpart W was indeed an "established program" at the time CAA § 136 was enacted, EPA must consider the fundamentally different purposes of CAA § 136 as compared to Subpart W in construing that section as a whole and the netting provisions in particular. The GHGRP and Subpart W were devised solely as an information gathering program. As such, the reporting mechanism – including identification of the relevant owner/operator for reporting purposes – was geared toward ease of information gathering and facilitating the collection of relevant and accurate information. In contrast, CAA § 136 is a fee program that has a wholly different purpose and effect than the GHGRP and Subpart W (e.g., creating an incentive for the reduction of methane emissions). More specifically, the netting provision clearly was intended by Congress as a way to incentivize methane emission reductions by reducing the WEC obligation. EPA thus has an obligation to take a fresh look at the term owner/operator under CAA § 136 to make sure the fee program regulations comport with the purposes of the program. From that perspective, allowing netting at the parent company level is appropriate because it would fully implement Congress's clear purpose of mitigating the impact of the fee program.

Moreover, EPA already correctly acknowledged that "for parent company [the highest level U.S. Parent company of owners (or operators)] reporting, the percent ownership in the facility is also reported under 40 CFR 98.3(c)(11). Because a parent company has an ownership interest in a subpart W facility multiple facilities may be said to be owned by the same parent company and might also be considered as being under common ownership or control of that parent company." While a subsidiary manages its own affairs and remains responsible for day-to-day operations, it is typically true that a parent company has sufficient investment oversight of the actions of its subsidiaries to reasonably have "ownership" or "control" solely for purposes of identifying the reporting entity

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[9] 89 Fed. Reg. at 5328

[10] *Id.*

[11] *Id.*

[12] *Id.*

under Part 98 and for netting under the WEC.[13]. Many parent companies file consolidated tax statements for their subsidiaries and have shared corporate functions. Furthermore, "control" of an entity should be considered for this purpose if the parent has at least a controlling shareholder interest, to be presumptively "under common ownership or control" of an affected facility. Also, capital investment decisions and resource allocation, as well as corporate strategies such as lower carbon initiatives, are generally done at the parent level. Netting at that level would allow for faster and more effective methane mitigation as parent companies will prioritize low-cost emissions reductions first across their entire portfolio.

More generally, EPA's assertion that its proposed approach reflects a "plain reading" of CAA § 136 is mistaken in any event. CAA § 136 allows for netting among applicable facilities under "***common*** ownership or control." CAA § 136(f)(4) (emphasis added). The term "common" naturally encompasses all operations within the ownership or control of a corporate entity. Nothing in CAA § 136(f)(4) suggests that the term "common" should be construed as being limited to operations owned/operated by the particular entity that reports under Subpart W, much less limited to a subsidiary of a larger corporate entity. Note that CAA § 136 requires emissions estimates under Subpart W to be used in implementing the WEC, but that does not mean that elements of Subpart W unrelated to quantifying emissions create any obligation or constraint under the WEC rule.

That is particularly true here, where the terms owner and operator under Part 98 were developed solely for the purpose of facilitating an information gathering regulatory program that is not governed by any specific CAA provision. As devised by EPA, netting is not a concept that has any meaning or relevance under Part 98 generally or Subpart W specifically. Thus, to give full effect to Congress's express direction to allow for netting under the WEC program among applicable facilities under common ownership or control, it is incumbent on EPA to construe those terms in the context of the WEC program and not limit the meaning of those terms to Part 98 rules that serve a wholly different purpose than the WEC program.

Moreover, the fact that the Subpart W approach to identifying the reporting entity predated CAA § 136 lends no additional support to EPA's proposed approach. That might have been true if CAA § 136 signaled some connection between the owner or operator for netting purposes and the owner or operator that reports under Subpart W. But Congress made no such connection between the two programs. Thus, the term "common ownership or control" in CAA § 136(f)(4) must be given its plain meaning.

EPA's proposed interpretation is therefore unfounded and unreasonable. The whole purpose of CAA § 136 is to identify what entities should pay a fee and to determine the amount of that fee. In proposing to define common ownership or control, EPA entirely fails to consider the effect of the various proposed methods of defining that term on the scope and extent of the fees that might be due under the program. Unless corrected (through further notice and comment rulemaking), that analytical failure will render the final rule arbitrary and capricious.

For these reasons, EPA's justification for the proposed netting provision is insufficient because the Agency failed to acknowledge, consider, and give full effect to the important role that Congress intended netting to play in mitigating the impact of the WEC program.

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[13] For the avoidance of doubt, a parent company may be deemed an owner or operator, or have control, of subsidiaries of facilities for purposes of GHG reporting and netting. However, this shall not be construed as indicating a parent company has direct ownership or operational responsibility for a particular facility or otherwise undermine the corporate separateness of a parent company and its subsidiaries that remain responsible for managing its day-to-day business and facility operation.

2.2 Facilities with less than 25,000 tpy GHG emissions should be allowed to net.

EPA proposes "that if a facility's emissions are not subject to the WEC, either because the facility is not a WEC applicable facility, or because a WEC applicable facility receives the regulatory compliance exemption, that facility's emissions do not factor into the netting of emissions for a WEC obligated party."[14] "In other words," EPA proposes that "only WEC applicable facilities may net, and only WEC applicable emissions may be netted."[15]

EPA explains that approach "is consistent with CAA section 136(f)(4) ''the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments identified in subsection (d),'' since the reference to ''applicable thresholds'' and ''applicable segments,'' which reflect other subsections under CAA section 136, implies that only WEC applicable emissions should be considered in the netting calculation."[16]

Limiting netting to only "WEC applicable facilities" is facially inconsistent with the plain text of CAA § 136(f)(4). The only relevant limiting provision in CAA § 136(f)(4) is the term "common ownership or control." Once common ownership or control is established, then the statute unambiguously allows netting of "facility emissions levels that are below the applicable thresholds within and across all applicable [industry] segments." Nothing in that language suggests or supports the limitation of netting only to "WEC applicable facilities."

EPA argues that facilities with less than 25,000 tons per year (tpy) of GHG emissions and facilities that qualify for the "regulatory compliance exemption" may not participate in netting because they are excluded from the program and, thus, cannot be considered "WEC applicable facilities."[17] But EPA's argument depends on its proposed definition of "WEC applicable facility" and not on the plain text of CAA § 136(f)(4). The proposed regulatory term "WEC applicable facility" describes facilities for which methane emissions must be determined and compared to the specified "waste emissions thresholds" – i.e., these are non-excluded facilities that are potentially liable for a waste emissions charge. While that proposed regulatory term may be useful in organizing the WEC regulations, that term is not prescribed by the statute and cannot be bootstrapped into a legal basis for imposing a constraint on netting that is not required by the statute.

The plain text of CAA § 136 dictates the proper outcome here. To begin, a facility with less than 25,000 tpy of GHG emissions plainly is an "applicable facility" because it is a "facility within [specified] industry segments, as defined in Subpart W."[18] That interpretation is reinforced by CAA § 136(c), which instructs that an "applicable facility that reports more than 25,000 metric tons" of GHGs may be required to pay a fee. That provision clearly connotes that a facility with less than 25,000 tons per year of GHG emissions still must be considered an "applicable facility."

Next, CAA § 136(f)(4) requires that "facilities under common ownership or control" must be allowed to net. The term "facilities" in that provision unambiguously is a reference to "applicable facilities," which as explained above, necessarily includes facilities with less than 25,000 tons per year of GHG emissions. Nothing in CAA § 136(f) reasonably suggests that the term "facilities" somehow can or should be construed as being limited only to what EPA proposes to define as "WEC applicable facilities" – i.e., those with GHG emissions greater than 25,000 tons per year and that have methane emissions less than the applicable waste emissions threshold.

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[14] 89 Fed. Reg. at 5329.

[15] *Id*.

[16] *Id*. at 5329-30.

[17] *Id.* at 5330-5332.

[18] CAA § 136(d).

Moreover, CAA § 136(f)(4) further provides that, for "facilities under common ownership or control," EPA must "allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds." Nothing in that provision limits netting only to facilities required to determine whether their methane emissions exceed an applicable waste emissions threshold. Rather, that provision plainly requires EPA to allow owners or operators without limitation to "account for" all "facility emissions levels that are below the applicable thresholds" – including emissions from facilities with total GHG emissions below 25,000 tons per year.

The plain text of CAA § 136 thus must be interpreted to allow facilities with less than 25,000 tons per year of GHG emissions to participate in netting. We note that, if there were ambiguity in the statute (which there is not for the reasons just stated), it would be unreasonable and arbitrary to adopt the proposed prohibition on including facilities with less than 25,000 tons per year GHG emissions from participating in netting. As explained above, CAA § 136(f)(4) plainly was intended by Congress as a program flexibility that would reduce the fees paid under the WEC program. That clear Congressional intent would be better effectuated by a broadly applicable netting rule (i.e., one that allowed applicable facilities with less than 25,000 tons per year of GHG emissions to participate in netting). As above, EPA's justification for this aspect of the proposed netting provision is insufficient because the Agency failed to acknowledge, consider, and give full effect to the important role that Congress intended netting to play in mitigating the impact of the WEC program.

EPA's proposed approach also would reduce a powerful incentive to reduce methane emissions. As proposed, within the context of the WEC once an applicable facility reduces its emissions to less than 25,000 tons per year, there is no incentive to accomplish further emissions reductions because additional reductions have no value under the Proposed Rule. If such facilities were allowed to participate in netting, further emissions reductions would be strongly incentivized because such reductions could be used in netting. At a minimum, an EPA failure to fully consider the practical implications of its proposed approach – including the incentives described here – would render this aspect of the final rule arbitrary and capricious.

3.0 The Proposed Unreasonable Delay Exemption Criteria Are Unduly Restrictive.

CAA § 136(f)(5) provides explicit exemption from the fee if emissions are caused by "unreasonable delay, as determined by the Administrator, in environmental permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation."

To implement the above statute, EPA proposes the following four criteria to govern implementation of that exemption: (1) "the facility must have emissions that exceed the waste emissions threshold; (2) neither the entity seeking the exemption, nor the entity responsible for seeking the permit, may have contributed to the delay; (3) the exempted emissions must be those (and only those) resulting from the flaring of gas that would have been mitigated without the permit delay, and the flaring that occurs must be in compliance with all applicable local, state, and Federal regulations regarding flaring emissions; and (4) a set period of months must have passed from the time a submitted permit application was determined to be complete by the applicable permitting authority."[19]

EPA's proposed criteria for implementing the unreasonable delay exemption are unduly restrictive given the various environmental permits required for oil and natural gas infrastructure. The unreasonable delay exemption

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[19] 89 FR 5332-5333

should provide maximum relief to operators when federal, state, or local agencies fail to issue permits in a timely fashion.

3.1 EPA should adopt a case-by-case process for determining whether an unreasonable delay in permitting has occurred.

Rather than limiting the unreasonable delay exemption by inappropriate and impractical brightline criteria, EPA should adopt a case-by-case process for determining whether an unreasonable delay in permitting has occurred. At a minimum, this case-by-case process should be an alternative to EPA's proposed criteria. Set timelines for applicant responsiveness and unreasonable delay for permit issuance do not recognize the complexity of environmental permitting for gathering and transmission infrastructure. A single pipeline project may require several environmental permits from various federal, state, and local agencies with different application procedures and review timelines. For example, a natural gas pipeline project may require the following federal, state, and local permits:

- Certificate of Public Convenience and Necessity from Federal Energy Regulatory Commission (FERC),
- Section 404 General Permit from the Army Corps of Engineers,
- Section 7 Threatened and Endangered Species Clearance from the Fish and Wildlife Service (FWS),
- Water and air permits from the state environmental agency, and
- Erosion and Sedimentation Control Plan Review from the County Conservation District.

The various permitting actions may occur in parallel or in sequence. An unreasonable delay for a prerequisite permit would delay a project even if subsequent permits are issued in a timely fashion. For example, a compressor station in Texas may require separate construction (i.e. New Source Review (NSR)) and operating (i.e. Title V) air permits; the Title V permit cannot be issued until the NSR permit authorization is approved.

Furthermore, environmental permitting for gathering and transmission infrastructure occurs on various spatial scales. An unreasonable delay in environmental permitting for a pipeline mainline could affect hundreds to thousands of production sites in a basin while a delay for a connecting line would impact one to a handful of sites.

Given the complexity in the environmental permitting for gathering and transmission infrastructure, EPA should allow companies to apply for a case-by-case exemption for methane emissions for an individual site up to an entire basin resulting from an unreasonable delay in permitting. Our comments on EPA's proposed brightline criteria for applicant responsiveness and an unreasonable delay for permit issuance by the agency are below.

3.1.1 The proposed brightline criteria for contribution to the delay are inappropriate and impractical.

EPA explains that contribution to the delay "would be determined based upon the timeliness of response to requests for additional information or modification of the permit application. Delays in response exceeding the response time requested by the permitting agency, or requested by the relevant production or gathering or transmission infrastructure entity seeking the permit, or responses that exceed 30 days from the request if no specific response time is requested, would be considered to contribute to the delay in processing the permit application."[20]

Such brightline rules are not appropriate because they do not reflect the actual ebb and flow of permitting actions. For example, if a permitting authority imposes an unreasonably short deadline for submitting supplemental information, the applicant will become ineligible for the exemption notwithstanding otherwise prompt and complete submission of the needed information. Similarly, a fixed 30-day default deadline ignores the likely possibility that, even with the best efforts by the applicant, certain additional information submissions will unavoidably take longer than 30 days to compile. EPA should allow for a subjective assessment in such cases rather than imposing brightline criteria.

Furthermore, the entity seeking the exemption does not have knowledge of or control over whether the entity seeking the permit has contributed to the delay in the case that the entity seeking the exemption and the entity seeking the permit are under different parent companies. For this case, the lack of knowledge or control makes this criterion impractical to implement for the entity seeking the exemption. Also, in the case of a large pipeline project, unresponsiveness from the entity seeking the permit would unfairly disqualify several other entities from this exemption through no fault of their own.

3.1.2 The proposed brightline criteria for defining unreasonable delay do not reflect different permit issuance timelines for various agencies.

EPA suggests that an appropriate "set period of months" to assess unreasonable delay should be 30 to 42 months[21]. Again, such brightline criteria could unfairly cause an applicant to become ineligible for the exemption in situations where faster action by the permitting authority should be expected. Reasonable permit issuance timelines vary by agency and by permit type. For example, the Texas Commission on Environmental Quality (TCEQ) has published target permit issuance time frames[22] for air permits ranging from 45 days for the simplest authorizations to 12 months for the more complex permits. API notes that these timeframes are much less than EPA's proposed range but also recognizes that longer time frames are expected for other agencies and permits.

Another example is the Right-of-Way (ROW) process for the Bureau of Land Management (BLM). A ROW is required for every project built on public land including each connecting line to an existing gathering pipeline or electrical transmission line. After an initial evaluation, BLM notifies the applicant on whether the application can be processed within 60 days. Considering this goal timeline, an unreasonable delay in ROW permitting would likely not be 30 to 42 months but would still result in methane emissions from flaring (where otherwise allowed), generator engines, and other activities due to that delay.

As above, EPA should provide leeway for the assessment and application of situation-specific facts and circumstances. Therefore, EPA should adopt a case-by-case process for determining whether an unreasonable delay in permitting has occurred.

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[20] 89 FR 5332
[21] 89 FR 5334
[22] TCEQ - Factsheet - Air (APD-ID 32v1.0, Revised 06/21). https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/permit-factsheet.pdf Accessed February 22, 2024.

3.2 EPA unduly restricts exempted emissions to those from flared gas which are not the only emissions resulting from unreasonable delay in environmental permitting for gathering and transmission infrastructure.

Rather than limiting exempted emissions to flaring, EPA should allow operators to determine the methane emissions that result from an unreasonable delay in environmental permitting for gathering and transmission infrastructure. These exempted emissions would be determined on an individual site basis and then totaled and subtracted from the emissions on WEC applicable facility basis. Some examples of additional exempted methane emissions include, but are not limited, to the other compliance options under OOOObc for associated gas:

- **Use of gas as an onsite fuel source.** While API believes that combustion emissions should be included under Subpart C or at least exempted from the WEC, onsite combustion emissions that result from an unreasonable delay should be exempted.
- **Use of gas for a useful purpose that a purchased fuel or raw material would serve.** If an operator implements a process onsite to use the gas due to an unreasonable delay, those methane emissions should be exempted.
- **Use of gas for reinjection into the well or injection into another well.** An operator may choose to inject or reinject the gas rather than flare due to an unreasonable delay. All methane emissions associated with the injection process (e.g., combustion from compressor driver, reciprocating or centrifugal compressor, fugitive emissions components, etc.) should be exempted.

While the above options focus on methane emissions resulting from an unreasonable delay for gas infrastructure, methane emissions from storage vessels could also be caused by an unreasonable delay for liquid infrastructure. EPA should also allow operators to exempt emissions from generator engines due to an unreasonable delay for electrical transmission; generator engines were considered acceptable by EPA to power instrument air skids for OOOObc compliance for process controllers and pumps. Operators should have the maximum flexibility to determine which methane emissions are the result of an unreasonable delay and therefore should be exempt from the WEC.

3.3 EPA must clarify "in compliance with all applicable local, state and federal regulations regarding flaring emissions".

One of the proposed criteria for the unreasonable delay exemption is "[reported flaring emissions] are in compliance with all applicable local, state and federal regulations regarding flaring emissions". This criterion should be clarified in several ways.

- **"All applicable local, state and federal regulations regarding flaring emissions" should be limited to environmental regulations.** While the phrase "regarding flaring emissions" implies that the criterion is limited to environmental regulations, other agencies (e.g., state oil and gas commissions) also have regulations regarding flaring. To avoid potential confusion, EPA should clearly state that only applicable local, state and federal environmental regulations are relevant for the purposes of the unreasonable delay exemption.
- **"Compliance" means no proven or admitted violations to applicable environmental regulations.** EPA must specify that only violations that are proven through an adjudication or to which an entity admits liability would disqualify flaring emissions (or other potentially exempt emissions – see comment above) from this exemption. Also, refer to Comment 4.0 under the regulatory compliance exemption.

- **Facilities should not be subject to liability or interest if EPA or another environmental regulatory authority determines after the fact that violations existed.** Liability for potential violations is often not determined until well after the underlying event occurred. The time necessary to resolve enforcement actions should not result in interest charges because such interest charges would penalize entities for exercising their right against alleged violations. Also, refer to Comment 4.0 under the regulatory compliance exemption.

3.4 EPA must clearly define a "complete environmental permit application" as an administratively complete application.

Various environmental permitting agencies have different definitions and levels of completeness regarding permit applications. Typically, the first and simplest level of completeness is administratively complete, which means the application contains the required forms and supporting information for the agency to conduct a more detailed technical review. The submittal of additional or revised information during technical review does not make an environmental permit application administratively incomplete but is a typical and expected part of the agency review process. If EPA chooses to implement a set period of months to assess unreasonable delay, the clock should start after the application is deemed administratively complete by the appropriate permitting authority. Defining a "complete environmental permit application" as a technically complete application would unreasonably restrict the scope of this exemption and make it virtually meaningless.

3.5 Reporting and recordkeeping requirements associated with the unreasonable delay exemption should be streamlined.

Reporting and recordkeeping requirements associated with the unreasonable delay exemption should be limited to only those items necessary to verify that the exemption is met. While API recognizes that a case-by-case process may require more detailed information, EPA should make the reporting and recordkeeping requirements clear and fit-for-purpose. API has the following specific comments on the proposed reporting and recordkeeping requirements for the unreasonable delay exemption.

- **The attestation of responsiveness for the entity seeking the permit as proposed in § 99.31(b)(4) cannot reasonably be made by the entity seeking the exemption if it is a different entity.** The entity seeking the exemption does not have control or knowledge of the responsiveness of the entity seeking the permit in the case where the entity seeking the exemption and the entity seeking the permit are under different parent companies. Attestations should only be made for actions under the control of the entity making that attestation.

- **As proposed in § 99.31(b)(5)(ii), reporting *"[a] listing of methane emissions mitigation activities that are impacted by the unreasonable permitting delay"* is meaningful only if the scope of exempted emissions is expanded beyond flaring emissions.** Otherwise, operators will always report "sending natural gas to sales instead of flare" as the methane emissions mitigation activities. If EPA expands the scope of exempted emissions, operator should be able to simply identify the activities and associated methane emissions that were exempted.

- **The information proposed in §99.31(b)(10) should be limited to a certification statement only.** Specifically, *"Information on all applicable local, state, and federal regulations regarding flaring emissions and the facility's compliance status for each"* should be simplified to a certification that flaring complied will all applicable local, state, and federal environmental regulations regarding flaring emissions. EPA should not require detailed compliance information, such as annual reports, to determine eligibility for an exemption. Also, the compliance certification should be limited to environmental regulations only.

- **Records regarding the permit application should only be required for the entity seeking the permit.** The recordkeeping requirements proposed in 99.33(a) should clearly state that these records need only be kept by the entity seeking the permit.

- **EPA should only require the information on the permit application necessary to determine if an unreasonable delay has occurred.** As proposed in 99.33(a)(3), EPA is requiring "Information on whether the facility's response included modification to the permit application." This information is not necessary to determine if the exemption applies and implies that a technical update to the permit application would make the permit application "incomplete". As discussed above, a complete environmental application should be an administratively complete application. Technical updates to permit application are routinely submitted during the review process and do not necessarily "restart the clock" on determining if an unreasonable delay has occurred.

4.0 The Proposed "Regulatory Compliance Exemption" Unreasonably Limits the Scope of That Exemption.

CAA § 136(f)(6) provides an exemption from paying fees for applicable facilities that are "subject to and in compliance with methane emissions requirements pursuant to [CAA §§ 111(b) and (d)]" provided that "methane emissions standards and plans pursuant to [CAA §§ 111(b) and (d)] have been approved and are in effect in all States with respect to the applicable facilities" and compliance with those programs "will result in equivalent or greater emissions reductions as would be achieved by" the 2021 OOOObc proposed rule.

EPA proposes detailed rules for administering CAA § 136(f)(6).[23] As detailed below, several elements of those proposed rules are inconsistent with the statute or otherwise unreasonable.

4.1 An applicable facility should be eligible for the regulatory compliance exemption as soon as a state or federal program is approved and in effect for the state(s) in which that facility is located.

EPA proposes that the regulatory compliance exemption will become available only after "***all*** state and Federal plans pursuant to CAA section 111(d) are approved and in effect."[24] (emphasis added). More specifically, EPA "proposes to interpret ''all states'' in CAA section 136(f)(6)(A)(i) to mean that every state with an applicable facility (i.e., all states with Subpart W facilities containing CAA section 111(b) or (d) facilities) must have an approved plan (state or Federal) before" the exemption becomes available for any applicable facility.

That "all or nothing" approach is inconsistent with CAA § 136 and unreasonably limits availability of the exemption. CAA § 136 specifies that programs must be "approved" and "in effect in all States with respect to the applicable facilities."[25] The use of the plural in that provision does not compel EPA's "all or nothing" approach. Instead, the term "facilities" plainly is a reference back to the term "affected facility" in subsection (f)(6)(A). As

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[23] 89 Fed. Reg. at 5336-47.
[24] *Id*. at 5337
[25] CAA § 136(f)(6)(A)(i).

such, the law provides that applicability of the exemption should be determined on a facility-by-facility basis and that a facility should qualify as long as programs are "approved and in effect" for that particular facility. The use of the plural simply accommodates the possibility that a given facility might straddle a state line.

Moreover, the "all or nothing approach" unreasonably limits the availability of the exemption based on circumstances beyond the control of affected facilities and of states that promptly enact and obtain approval for their programs. It thus creates a perverse incentive for states to slow the implementation of their programs if it is apparent that other states are moving on a much slower timeline.[26]

Moreover, the "all or nothing approach" does nothing to incentivize the prompt development and approval of state programs by proactive states because such states would not realize any benefits for their regulated communities from the regulatory compliance exemption if they act early because implementation of the exemption would be held back by the lagging states. And, it would have the perverse effect of disallowing the exemption from continuing to apply anywhere in the Nation if a single approved state program anywhere in the Nation loses its EPA approval (e.g., through a successful legal challenge to EPA's approval in the litigation that inevitably will occur over EPA's approval decisions). Thus, EPA's proposed approach would make compliance planning virtually impossible and frustrate any settled expectations that come with program approval.

More generally, EPA's proposed approach also would infringe on the cooperative federalism that is a key feature of CAA § 111(d). That provision unambiguously requires EPA to implement the existing source program through a SIP-like program, where EPA provides the overarching program structure and each state develops and imposes the source specific emissions limitations and standards for the state. The "all or nothing" proposed approach to implementing the regulatory compliance exemption would unreasonably tie the states together in a way that prevents states from determining its own fate, as CAA § 111(d) clearly requires.

4.2 The regulatory compliance exemption should become available as soon as an applicable state or federal plan is in effect.

EPA "proposes that the exemption should become available as soon as all state or federal plans are ***in effect***, because facilities can be in compliance with the requirements in [a] plan even if full implementation of those requirements is not required until a future date."[27] (emphasis added). In other words, once an approved CAA § 111(d) program become effective, affected facilities subject to that program become eligible for the exemption even if emissions control requirements do not become applicable until later dates.

API supports such an approach. We agree with EPA's rationale. But we note that that approach is particularly appropriate because the statute unambiguously requires it.[28] The words "in effect" plainly refer to EPA's CAA § 111(b) new source regulations and state CAA § 111(d) existing source programs and not to the discrete components of those regulations and programs. As EPA aptly explains, that stands to reason because "It is [] possible for CAA section 111(d) facilities to be in compliance with the methane emissions requirements in a plan even if not all compliance dates included in the plan have come to pass."

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[26] We note that EPA assumes in the RIA that the regulatory compliance exemption will become available in 2027. That is an unreasonable and unfounded assumption – especially in light of the proposed "all or nothing" approach, which virtually guarantees that the exemption will not be available that early.

[27] 89 Fed. Reg. at 5338

[28] See CAA § 136(f)(6)(A)(i) (the regulatory compliance exemption becomes available when relevant "standards and plans pursuant to subsections (b) and (d) of [CAA § 111] have been approved and are ***in effect*** ….") (emphasis added).

4.3 API opposes the "all or nothing" approach to implementing the regulatory compliance exemption but supports EPA's rationale for a national equivalency evaluation if EPA implements the "all or nothing" approach.

EPA proposes that "a national evaluation is the most appropriate geographic scale for the purposes of the equivalency determination" with the 2021 proposed OOOObc.[29] EPA argues that "[b}ecause the climate impacts of these emissions are dependent on their aggregate quantity rather than where they occur, a national-level evaluation will provide an appropriate comparison of the overall impact of the reductions that would have been achieved under the NSPS OOOOb/EG OOOOc 2021 Proposal and those that will be achieved upon implementation of the final NSPS OOOOb and state and Federal plans implementing OOOOc."[30]

As explained in subsection A above, API opposes EPA's proposed "all or nothing" approach to implementing the regulatory compliance exemption. However, we agree with EPA's assertion that the potential "climate impacts" of GHG emissions "are dependent on their aggregate quantity rather than where they occur."[31] In other words, local GHG emissions reductions do not directly alleviate any potential climate-related local public health or air quality impacts related to those emissions because aggregate global GHG emissions produce largely homogenous global atmospheric concentrations of GHGs. Thus, any potential "climate impacts" attributable to anthropogenic GHG emissions at any particular location are a product of global activity and global atmospheric conditions.

4.4 The fact that a state plan properly employs "RULOF" to derive alternative emissions standards that are less stringent than EPA's proposed emissions guidelines does not make that plan less stringent than EPA's 2021 proposed rule.

EPA proposes that "the inclusion of the NSPS OOOOb/EG OOOOc 2021 Proposal as the baseline for the equivalency demonstration to mean that Congress intended for the EPA to assume, for purposes of [the state equivalency] analysis, that the proposed standards were finalized as drafted in the NSPS OOOOb/EG OOOOc 2021 Proposal and implemented nationwide."[32] EPA observes that "it is possible that some states may [] set different standards of performance than the presumptive standards proposed in EG OOOOc based on a provision of CAA section 111(d)(1) permitting states to ''take into consideration, among other factors, the remaining useful life of a source.'' (The EPA refers to this provision as the ''remaining useful life and other factors'' provision, or RULOF.)"[33]

According to EPA, "In such circumstances, the emissions reductions achieved by those state plans would have been less than if the state plans had adopted and implemented the presumptive standards in the final emissions guidelines, had they been finalized."[34] But EPA asserts that "because state plans were never developed pursuant to the NSPS OOOOb/EG OOOOc 2021 Proposal, there is no means of reasonably estimating the requirements that may have been included in those state plans and what emissions reductions they would have achieved."[35] EPA thus proposes that it will not consider the possibility of RULOF-based state standards in determining the baseline program effectiveness to be used in making program equivalency determinations. EPA argues that approach "is aligned with a plain reading of CAA section 136(f)(6)(A)."[36]

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[29] Notice at 5341.
[30] *Id.*
[31] *Id.*
[32] *Id. at 5341.*
[33] *Id. at 5342.*
[34] *Id.*
[35] *Id.*
[36] *Id. at 5341.*

The effect of EPA's proposed approach is to cause any state plan containing RULOF-based emissions limitations or standards that are "less stringent" than the corresponding emissions guidelines in the 2021 proposal to be less stringent than the 2021 proposal, unless the state otherwise imposes sufficiently more stringent emissions limitation or standards on other sources to make up the difference. If EPA adopts a state-by-state approach to making equivalency determinations (as it must for the reasons explained above), that means that no state plan containing RULOF-based emissions limitations or standards could be determined by EPA to provide equivalent emissions reductions as the 2021 proposal unless the state achieves greater than needed emissions reductions in other ways.

EPA's proposal is flawed for two reasons. First, as API explained in its comments on the 2021 Proposal, that proposal is not a legally cognizable proposed rule because it did not contain and otherwise was not accompanied by proposed regulatory text.[37] Consequently, in construing and applying CAA § 136(f)(6)(A)(ii), ***any*** state plan will "result in equivalent or greater emissions reductions as would be achieved by [the 2021] proposed rule" because that proposed rule did not propose legally cognizable emissions limitations or standards that could possibly have resulted in emissions reductions. Thus, inclusion of RULOF-based emissions limitations or standards in a state plan would not cause that state plan to produce fewer emissions reductions than strict adherence to the 2021 "proposed rule."

Second, the 2021 proposed rule acknowledged and accommodated the possibility of less stringent state standards based on consideration of RULOF.[38] Indeed, EPA could do no less because, as EPA states, "the statute requires" states to have that authority. [39]

Thus, the possibility of less stringent RULOF-based state standards ***was*** incorporated into the 2021 proposed rule. As a result, EPA cannot reasonably conclude that the baseline for equivalency determinations cannot include the possibility of RULOF-based standards. A plan with adequately justified RULOF-based standards necessarily would achieve at least as much emissions reductions as the 2021 proposal would require because such standards were embraced (as EPA legally must) in that proposal.

4.5 EPA must consider the overall emissions reductions achieved by state plans and not just those emissions reductions that would be achieved by the sources addressed in the 2021 proposed rule.

We note that the 2021 proposal did not include at least one source type covered by the 2022 supplemental proposal.[40] Moreover, the 2022 supplemental proposal provides regulatory details about certain provisions that were addressed only in concept in the 2021 proposal.[41] Such conceptual elements of the 2021 proposal do not constitute and cannot reasonably be construed as constituting a proposed emissions limitation or standard for purposes of making equivalency determinations under CAA § 136(f)(6)(A)(ii).

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[37] Letter from Frank J. Macchiarola to The Honorable Michael S. Regan (Jan. 31, 2022) (docketed at EPA-OAR-2021-0317-0808) at 55.

[38] 86 Fed. Reg. 63110, 63251 (Nov. 15, 2021) ("To the extent that a State determines the presumptive standards in the final EG are not reasonable for a particular designated facility due to remaining useful life and other factors, the statute requires that the EPA's regulations under CAA section 111(d) permit States to consider such factors in applying a standard of performance.").

[39] CAA § 111(d)(1).

[40] 87 Fed. Reg. 74702, 74707 (Dec. 6, 2022) ("[T]he EPA is proposing methane and VOC standards for one new emission source that is currently unregulated (i.e., dry seal centrifugal compressors).")

[41] See, e.g., 86 Fed. Reg. at 63177 (Where EPA asked for comment on a concept, but not an actual proposed rule, "on how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event.").

As a result, the 2022 supplemental proposal would regulate additional source types and activities than the 2021 proposal. Moreover, as long as they are consistent with CAA § 111 standard setting criteria, states have further latitude to regulate source types and activities in their CAA § 111(d) existing source programs than EPA nominally would regulate under its emissions guidelines.

CAA § 136(f)(6)(A)(ii) requires equivalency determinations to consider the emissions reductions that would be achieved by approved state CAA § 111(d) plans versus reductions that would have been achieved under the 2021 proposed rule. Thus, EPA must make it clear in the final rule that the overall emissions reductions achieved by state plans must be considered in making equivalency determinations and not just the emissions reductions that would be achieved by the program elements proposed in 2021.

4.6 A proven or admitted violation should disqualify only the Subpart OOOO/a/b/c affected or designated facility from the regulatory compliance exemption.

EPA proposes "to interpret and implement the regulatory compliance exemption such that an applicable Subpart W facility that contains any CAA section 111(b) or (d) facilities would be eligible for the exemption once all other criteria are met."[42] Under that interpretation, an entire applicable facility becomes ineligible for the regulatory compliance exemption when a violation is proven or admitted, even when the violation involves only a subset of the equipment or operations at the facility. The Industry Trades object to that "all or nothing" approach.

Instead, if a violation is proven or admitted, the regulatory compliance exemption should be disallowed only for the particular Subpart OOOO, OOOOa, OOOOb, or OOOOc applicable or designated facility that is in violation. For example, under Subpart OOOOa, the pneumatic controller applicable facility is each individual pneumatic controller.[43] Thus, if a particular pneumatic controller is determined or admitted to be out of compliance with Subpart OOOOa requirements, only that controller should be excluded from the regulatory compliance exemption. The remainder of the applicable facility should continue to qualify for the exemption.

That approach comports with CAA § 136(f)(6)(A) because the term "compliance" necessarily only applies to the parts of applicable facilities that are subject to Subpart OOOO requirements. Moreover, because the Subpart OOOO rules apply to discrete applicable or designated facilities, it is not reasonable or sensible to extend the consequences of a proven or admitted violation to equipment or operations beyond the applicable or designated facility that is in violation.

Also, EPA's approach will, as a practical matter, deprive the regulatory compliance exemption of its intended effect because even a single violation at a single piece of equipment would make the entire applicable facility (as proposed, "applicable facility" in this instance meaning the entire Subpart W reporting basin, which compounds the issue as such a "facility" would substantially expand the number of sites with OOOObc "affected facilities") ineligible for the exemption for an entire year. While owners and operators strive for 100% compliance, perfection often is unattainable – especially given the nature of the Subpart OOOO rules, which result in hundreds of thousands of discrete compliance obligations for even modest sized facilities in any given year. In short, EPA's proposed approach would render the regulatory compliance exemption a near nullity under the WEC program, which is wholly inconsistent with Congress's clear intention that the exemption should provide a practical and

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[42] 89 Fed. Reg. at 5343.

[43] 40 C.F.R. § 60.5390.

meaningful way to avoid paying fees under the WEC while still achieving the methane emissions reductions the WEC otherwise would incentivize.

Lastly, EPA states that "[f]or the purpose of determining WEC facility eligibility for the regulatory compliance exemption, the EPA proposes that the compliance status of CAA section 111(b) and (d) facilities contained within a WEC applicable facility would be assessed based on compliance with the applicable methane emissions requirements for the Oil & Natural Gas Source Category (40 CFR part 60, Subparts OOOOa, OOOOb, and OOOOc)."[44] API supports that interpretation. Indeed, the reference to "methane emissions requirements" in CAA § 136(f)(6)(A) unambiguously is a reference to standards applicable to sources in the oil and natural gas sector, which Congress understood to be prescribed by the NSPS OOOO series of rules. Thus, no other interpretation is permissible.

4.7 An applicable facility should be considered "in compliance" with methane emissions standards unless a violation is proven through adjudication, or the violation is admitted by the owner or operator of the affected facility.

"The EPA is proposing that a WEC applicable facility would not be eligible for the regulatory compliance exemption if any CAA section 111(b) or (d) affected facility that is contained within the WEC applicable facility has one or more deviations or one or more violations of any methane emissions requirement under the applicable NSPS or state or Federal plan issued pursuant to the EG."[45] That element of the Proposed Rule is flawed for two reasons.

First, it would apply to "deviations," which is a term that does not necessarily connote a violation of applicable requirements. For example, EPA's Part 71 federal Title V permitting rules unambiguously provide that "[a] deviation is not always a violation."[46] Thus, "deviations" should not be covered by the rule and should not constitute a disqualifying event. Under the oil and gas NSPS specifically, the fact that there is an established process to report deviations is an indication that EPA understands and expects there to be deviations from the rule. Therefore, penalizing self-reporting seems counterproductive.

Second, in the Proposed Rule, EPA assumes without analysis or explanation that the owner or operator of an applicable facility has the burden of affirmatively certifying that the facility is "in compliance" in order to qualify for the regulatory compliance exemption. That assumption in itself is a flaw in the Proposed Rule because the burden of proof is a key legal aspect of the regulatory compliance exemption and, thus, EPA has an obligation to explain the legal, policy, and factual bases for its proposed interpretation.

But more importantly, a cornerstone of our legal system is that a person is considered innocent until proven guilty. That is reflected in the Agency's well-established enforcement practices, where a "notice of violation" or "finding of violation," which typically marks the start of a formal civil enforcement action, represents a mere allegation of a violation and is not a legally binding definitive finding of violation. Such a definitive determination of noncompliance may be achieved only through adjudication or by admission of the liable party.

Here, the term "deviation" again becomes relevant. For example, under the Title V operating permit program, each permittee is required to submit an annual compliance certification with the terms and conditions of the

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[44] *Id*. at 5344.

[45] *Id*. at 5344, bottom right.

[46] 40 C.F.R. § 71.6(a)(3)(iii)(C).

permit.[47] But that requirement specifically requires that the certification "shall identify each ***deviation*** and take it into account in the compliance certification."[48] (emphasis added). Thus, the annual compliance certification does not require certification of "violations." Instead, it requires certification against potential "deviations," which may or may not constitute a violation. The term "deviation" was intentionally used in that provision to prevent a Constitutionally unsound interpretation that would require affected sources to certify to the existence of violations which, given the potential criminal liability that might arise due to noncompliance with Title V requirements, would unlawfully require responsible officials to incriminate themselves.

Thus, the burden of proof of noncompliance rests with the government (or others authorized to enforce CAA applicable requirements).[49] Applied here, that means that the owner or operator of an applicable facility should be considered to be "in compliance" for purposes of the regulatory compliance exemption unless, for the given reporting year, a violation of applicable NSPS OOOO/a/b/c requirements is determined through adjudication or admission by the owner or operator of the applicable facility.

We note that EPA proposes to require applicable facilities seeking to qualify for the regulatory compliance exemption to submit a compliance certification as part of their application for the exemption.[50] For the reasons explained above, that requirement should not be finalized.

4.8 The proposed scope of compliance determinations is unreasonably broad and unworkable.

According to EPA, "there are many potential elements to compliance with the methane requirements promulgated under CAA sections 111(b) and (d), such as compliance with a quantitative emissions limit and compliance with work practice standards, as well as multiple monitoring, recordkeeping, and reporting requirements."[51] EPA proposes that "a deviation or violation from any of the methane requirements promulgated under CAA sections 111(b) and (d) constitutes non- compliance for purposes of the regulatory compliance exemption."[52] This element of the proposal is flawed for two reasons.

First, CAA § 136(f)(6)(A) specifies that applicable facilities must be in compliance with "methane emissions requirements." The subsequent subparagraph uses the term "methane emissions standards."[53] Those terms should be interpreted in concert to mean just the parts of the OOOObc rules that limit emissions, and not the additional administrative requirements that accompany the emissions standards. Indeed, the term "emission standard" is defined at CAA § 302(k) to mean "a requirement … which limits the quantity, rate, or concentration of emissions of air pollutants." Under that definition, the term "methane emissions standard" must be interpreted to apply only to emissions reduction measures. As EPA itself emphasizes, the purpose of the regulatory compliance exclusion is to encourage emissions reductions. Thus, eligibility for the exclusion should depend only on compliance with requirements that actually result in emissions reductions.

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[47] *Id.* at § 70.6(c)(5).
[48] *Id.* at § 70.6(c)(5)(iii)(C)
[49] That is particularly true here because CAA § 136 does not impose an obligation on owners/operators to demonstrate compliance, which stands in sharp contrast to other CAA provisions where such an obligation is expressly imposed. See, e.g., CAA § 114(a)(3) ("The Administrator shall in the case of any person which is the owner or operator of a major stationary source, and may, in the case of any other person, require enhanced monitoring and submission of compliance certifications.").
[50] 89 Fed. Reg. at 5346
[51] *Id.* at 5345.
[52] *Id.*
[53] *Id.* at § 136(f)(6)(A)

Second, EPA should exclude violations that do not result in any excess emissions. Again, the whole point of the exemption is to encourage and incentivize emissions reductions. Violations that do not result in any excess emissions that stand to materially impede program effectiveness do not compromise that goal of the exemption. Moreover, excluding such violations will make implementation of the exclusion more manageable and predictable.

More broadly, consistent with our comments above for the proposed netting provision, the "regulatory compliance exemption" was plainly intended by Congress to be a program flexibility that would reduce the fees paid under the WEC program. That clear Congressional intent would be better effectuated by broadly applicable rules for implementing the regulatory compliance exemption rather than the highly constrained approach that EPA proposes here. EPA's justification for the proposed rules for implementing the regulatory compliance exemption is insufficient because the Agency failed to acknowledge, consider, and give full effect to the important role that Congress intended that exemption to play in mitigating the impact of the WEC program.

Lastly, the "regulatory compliance exemption" is an exemption from paying fees and not an exemption from the WEC program. Thus, any proven or admitted noncompliance should preclude application of the exemption only for the period that the noncompliance exists. Thus, if a noncomplying event lasts for just one day, the exemption should be available for the remaining days of the reporting year. For the part of the year that the exemption is not applicable (in this example, for the one day), the owner or operator of the applicable facility should be required to pay a fee if emissions during that period exceed the applicable waste emissions threshold.

4.9 An owner or operator that does not claim the regulatory compliance exemption should not be required to report information that would otherwise be required to confirm the applicability of the exemption.

The Proposed Rule at § 99.42(d) appears to require an owner or operator to submit information related to implementation of the regulatory compliance exemption even in cases where the owner or operator does not seek to claim the exemption. For obvious reasons, that reporting requirement should be revised to apply only to those seeking to claim the exemption. For example, it appears that all facilities must prepare and report compliance certifications for all applicable facilities – including those for which the regulatory compliance exemption is not claimed. Because compliance certifications are not needed for any purpose under the WEC except to demonstrate eligibility for the regulatory compliance exclusion, the requirement to prepare and submit certifications should not extend beyond facilities for which the exemption is sought.

We note that EPA itself emphasizes that "[w]here a WEC obligated party represents that each CAA section 111(b) and (d) facility is in compliance, but the EPA or another regulatory authority subsequently discovers the existence of one or more deviations or violations, or the CAA section 111(b) and (d) facility identifies the deviation or violation as a result of an EPA investigation (including information requests), the WEC obligated party may be subject to enforcement and required to pay any outstanding fees and interest penalties."[54] More importantly, EPA emphasizes that "[f]alse statements may be subject to criminal enforcement."[55] Thus, imposing an unneeded and unwarranted broadly-applicable compliance certification obligation also would unreasonably expose owners/operators to enforcement liability.

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[54] 89 FR at 5346.

[55] *Id.*

5.0 Exemption for Permanently Shut-in and Plugged Wells

CAA § 136(f)(7) provides that "[c]harges shall not be imposed with respect to the emissions rate from any well that has been permanently shut-in and plugged in the previous year in accordance with all applicable closure requirements, as determined by the Administrator." The EPA proposes that "the methane emissions eligible for the exemption are those that occur at the well level including those from wellhead equipment leaks, liquids unloading, and workovers with and without hydraulic fracturing in the reporting year in which the well was plugged."[56]

5.1 EPA should expand the methane emissions eligible for the exemption to all methane emissions from all equipment and processes that were associated with the permanently shut-in and plugged well.

EPA's proposal for implementing the exemption for emissions from plugged wells does not fully implement the statute since EPA is choosing to limit emissions from the wellhead and associated activities only. EPA should not limit the emissions eligible for the exemption to just those "that occur at the well level." Instead, EPA should implement the alternative of allowing owners/operators to quantify the emissions reductions from other on-site sources attributable to the well closure including the following:

- Emissions from natural gas driven process controllers on the wellheads (e.g. emergency shutdown, plunger-lift controls) should be eligible for the exemption.
- Emissions associated with the storage vessels that may now have reduced throughput as a consequence of the well closure.
- Emissions from permanently plugged natural gas storage wells and related equipment.

Additionally, EPA was incorrect to exclude emissions from facilities that are below the waste emissions threshold from the exemption.[57] This limitation is not supported by the clear statutory requirement that "charges shall not be imposed" for emissions associated with plugged wells because it precludes the netting of emissions attributable to plugged wells that fall below the applicable waste emissions threshold.

5.2 EPA must avoid imposing reporting and recordkeeping requirements that are duplicative with other existing well closure requirements.

EPA must avoid reporting and recordkeeping requirements that are duplicative with other well closure requirements. Well closure requirements are within the jurisdiction of State Oil & Gas Commissions and other agencies, not the EPA. Under state law, a well is required to be plugged and abandoned when it has reached the end of its useful life. In all States, operators must provide written notice of plugging and comply with regulatory requirements to plug and abandon the well, including removing equipment, setting downhole plugs, cementing in the casing, capping the well to prevent fluid migration and restoring the surface site. These practices are done to permanently confine oil, gas and water into the strata in which they were originally found. For wells located on federal lands, separate BLM requirements also apply for well closure. Depending on the well location (e.g., located in an area with potash mining), additional requirements may also apply. EPA has also finalized closure plan requirements under OOOObc, see Attachment A for API's detailed comments on these requirements. EPA

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[56] *Id.* at 5348.

[57] 89 FR 5347

must avoid adding a potentially fifth set of recordkeeping and reporting requirements related to well closure with the exemption for permanently shut-in and plugged wells under WEC.

States have jurisdiction on closure requirements and inclusion of attestation that the closure has been conducted per appropriate requirements would be appropriate for the purposes of implementing the WEC. However, EPA is proposing in § 99.51 (a)(3) that operators submit "the statutory citation for each applicable state, local, and federal regulation stipulating requirements that were applicable to the closure of the permanently shut-in and plugged well." This level of information is unnecessary to verify the exemption and adds no environmental benefit under the WEC because it creates an opportunity for operators to inadvertently miss a citation. A missed citation for this reporting effort would not necessarily mean that the requirements were not followed during the permanent well closure. EPA should remove this list of citations from the reporting requirements.

6.0 Deadlines and Related Provisions

6.1 EPA's delay in setting up the supporting regulatory infrastructure should cause the WEC program to be deferred until 2025 or beyond.

The plain text of CAA § 136(g) specifies that the WEC "shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter." Additionally, CAA § 136(h) also required EPA to revise the requirements of Subpart W to more accurately reflect the total methane emissions and waste emissions for which an operator must demonstrate how much of a fee is owed. While EPA has proposed amendments to Subpart W, the final rule will not be promulgated until later in 2024. Likewise, EPA will not be able to promulgate the final WEC rule until later 2024. Moreover, under § 136(f)(6) the statute explicitly provides an exemption for operations that are in compliance with OOOObc, which has only recently been finalized.

Given EPA's delay in setting up the regulatory infrastructure that is necessitated in support of the statute, initiation of the WEC program should be deferred until the calendar year when all connected requirements and compliance obligations under both Subpart W and OOOObc are fully in effect.

6.2 EPA must redefine what constitutes a substantive error during validation of submitted Subpart W reports, which are the basis for the WEC.

As EPA explains in the preamble, while there is an annual March 31 deadline for submitting Subpart W reports, that "deadline" marks the beginning of a validation process that allows for Subpart W reports to be updated well after initial submission (in some cases, years after).[58] This validation process occurs within the e-GGRT platform whereby EPA sends operators questions.[59] Operators can respond via a text-based response and/or resubmit their emissions report. Many times, these queries can be closed without further action or only necessitate an administrative update where no change in reported emissions occurs to fully close the query. When an operator response does result in a change of total reported emissions these changes are often de minimis or immaterial to the overall reported emissions.

EPA must consider the impact of its inquiries during the validation process given that Subpart W is now the basis for calculating the WEC fee. At minimum, EPA should limit inquiries after WEC payments are received to those

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[58] 89 FR 5350

[59] We note that this validation process is not typical under any other EPA emission reporting program.

that could result in a true substantive change[60] of reported emissions under Part 98. API and other trades suggested 5% of a facility's total emissions as substantive in comments submitted on EPA's proposed Subpart W, which we have included as Attachment B. This would reduce the administrative burden for both EPA and operators by focusing queries on topics that are most important to emissions quantified. Consistent with our comments pursuant to proposed Subpart W included in Attachment B, this still provides time for EPA to validate emissions, but cease the seemingly unending questioning that continue to arise on Subpart W reports years after they have been originally submitted under Part 98.[61]

6.3 The WEC Filing, including payment, should occur only when both Subpart W and WEC filings have been validated to avoid a prolonged cycle of additional payments or refunds.

As proposed, EPA has created an untenable timeline for processing data, making payments, validating data, and refunding partial payments. Instead, EPA should make the reporting/validation/correction processes under the two programs wholly consistent, meaning that WEC filings should be based on validated Subpart W data and the WEC payment should be due after the WEC filing has been confirmed by EPA.

In order for a designated representative to certify the WEC filing, additional checks on ALL calculations, including all Subpart W calculations, would be necessary prior to submitting the WEC. Setting the WEC filing deadline to be the same as the Subpart W reporting deadline effectively pushes up when operators would need to complete the Subpart W calculations because the WEC filing can only be completed after all Subpart W reports are completed by an operator and additional lead time is needed to process the payment to go with the WEC filing.

Therefore, we offer the following amended timeline to support a more tenable workflow pursuant to the WEC:

- **Operators submit emissions reports pursuant to Subpart W by March 31 for the prior calendar year emissions, as required under 40 CFR Part 98.**
- **The proposed WEC filing deadline should be delayed until November 1 under proposed Part 99**. The emissions reported under Subpart W are the starting point for the WEC, but the WEC includes additional calculations and assessments that will require additional time to complete.
    - The delay to November 1 for the WEC Filing provides EPA time to conduct preliminary verification on reported values, which increases certainty on the regulated community. This timeline also coincides with the usual schedule of when EPA publicly publishes Subpart W data within the FLIGHT database and in other publications after conducting their initial validation/verification process.
    - The additional time also allows operators to assess and review their WEC filing and estimate their fee. A later deadline will allow operators to:

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[60] Per the GHG Protocol: *"A threshold is often used by verifiers to determine whether an error or omission is a material discrepancy or not. A material discrepancy is an error (for example, from an oversight, omission or miscalculation) that results in a reported quantity or statement being significantly different to the true value or meaning. As a rule of thumb, an error is considered to be materially misleading if its value exceeds 5% of the total inventory for the part of the organization being verified."* This is a relevant marker in determining if any omission influences the outcome in a meaningful way. We note here that materiality as discussed in the context of GHG emission reporting is highly variable and different from how the concept of "materiality" is defined per the Securities and Exchange Commission. Here we refer to materiality as defined and referenced strictly in the GHG Protocol Corporate Standard as a reference for how EPA should redefine what classifies a truly substantive error under the GHGRP.

[61] We note that this concept varies from how EPA reviews the concept of a 'substantive' change, which are essentially includes any change that might be required to the report – even if minor or administrative in nature.

        - Carefully consider potential exemptions and perform the necessary netting and additional calculations that are part of the WEC filing. Completing these additional calculations at the same time as completing the annual Subpart W emission report is untenable as proposed.
        - Review and resubmit information reported under Subpart W that may be identified on the part of the operator during preparation of the WEC filing. This will alleviate the administrative burden of both operators and EPA in the overall validation process ahead of the WEC filing.
        - Review their OOOObc compliance records, which are due on a differing reporting cycle than Subpart W. This could also alleviate the burden associated with resubmitting the WEC filing as even EPA acknowledges that OOOObc compliance reports will not be complete by March 31 each year[62].

- **The deadline for submitting the WEC Payment that is part of the proposed WEC Filing should also be delayed until November 1 under Part 99.**
    - We agree that any fee should be due in the same year the emissions are reported to not prolong uncertainty in capital planning associated with the fee. Also, the administrative burden of additional fee collection and refunds due to fee corrections would be reduced by delaying payment until November 1. We also agree with EPA assertions that any Subpart W report that is resubmitted after November 1 that impacts the WEC calculations would not necessitate a revised WEC filing; operators could continue to resubmit data under Subpart W at any time.
    - Companies often have lead times to have funds approved or checks issued. It is impractical for operators to complete their emission reports and be prepared to issue a check associated with the emissions quantified at the same time, especially given the additional calculations associated with the WEC framework (including exemptions).
    - WEC payments resulting from any revision during the validation process of WEC filings should not be subject to interest or penalties.

6.4 EPA should establish a consistent requirement that relevant records under Subpart W and the WEC program must be retained only for three years following a given reporting year.

EPA should establish a consistent requirement that relevant records under Subpart W and the WEC program must be retained only for three years following a given reporting year. To provide needed repose for owners/operators, that three- year deadline also should mark the end of EPA's and the owner/operator's opportunity or obligation to file amended reports and to amend any required WEC payments.

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[62] 89 FR 5346

7.0 Facility Definition

7.1 EPA's proposed approach is procedurally inadequate because EPA does not provide any meaningful legal, policy, or factual analysis of the statutory term "applicable facility" as it relates to defining the geographic bounds of such facilities and no explanation as to how the approach for reporting facility level emissions under Subpart W satisfies the meaning of "applicable facility" under CAA § 136.

EPA proposes that an "applicable facility" means "a facility within one or more … industry segments, as those industry segment terms are defined in §98.230 of this chapter."[63] EPA explains in the preamble that that definition includes a "facility for which the owner or operator of the Subpart W reporting facility reported GHG emissions under Subpart W of more than 25,000 mt CO2e."[64] EPA further explains that "[i]n cases where a Subpart W facility reports under two or more of the industry segments listed in the previous paragraph, the EPA proposes that the 25,000 mt CO2e threshold would be evaluated based on the total facility GHG emissions reported to Subpart W across all of the industry segments (i.e., the facility's total Subpart W GHGs)."[65] EPA provides no further regulatory text or preamble discussion to elaborate on the boundaries of an "applicable facility."

Although it is far from clear in the Proposed Rule, it appears that EPA intends the WEC rule to be implemented according to how facility level emissions must be reported under Subpart W. In other words, EPA effectively relies on Subpart W reporting requirements for defining the geographic bounds of an "applicable facility" under the WEC rule. That aspect of the proposed rule is flawed because EPA fails to provide adequate explanation or justification for taking that approach.

The crux of the problem is that CAA § 136 states that an "applicable facility" is a "facility" within specified industry segments "as defined in Subpart W."[66] The reference to Subpart W plainly is a reference to the industry segments already defined in Subpart W and not a reference to how emissions sources must be grouped for purposes of estimating and reporting emissions under Subpart W. Thus, the CAA § 136 definition of "applicable facility" leaves open the question of what are the geographic bounds of a "facility" under the WEC program?[67]

In other circumstances, the term "facility" refers to a plant-like collection of equipment or operations that is under common ownership or control and that is contained within a geographically contiguous or adjacent area. Such plant-like facilities are not uncommon in the oil and gas production sector. For example, a natural gas processing plant often comprises a discrete plant-like facility.

But the generally dispersed nature of functionally interrelated upstream oil and gas production has made it difficult in some circumstances to determine the physical bounds of a facility for CAA regulatory purposes. EPA has observed that "well sites can be located hundreds of miles from the natural gas processing plant, and some oil and gas operations (e.g., a production field) can cover many square miles."[68] Adding to that complexity is the fact that "unlike many industries, land ownership and control are not easily distinguished in this industry, because

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[63] 89 FR 5367.

[64] 89 FR 5324.

[65] *Id.*

[66] CAA § 136(d).

[67] Notably, EPA did not address the definition of "facility" or "applicable facility" in the recent proposed changes to Subpart W of the GHGRP. EPA explained that "implementation of the waste emissions charge is outside the scope of this rulemaking." 88 Fed. Reg. 50282, 50286 (Aug. 1, 2023).

[68] Memo from William L. Wehrum to Regional Administrators I-X, Source Determinations for Oil and Gas Industries (Jan. 12, 2007) at 2.

subsurface and surface property rights are often owned and leased by different entities, and drilling and exploration activities are contracted to third parties."[69] Moreover, [w]hile it is not uncommon for a single company to gain the use of a large area of contiguous property through these lease and mineral rights agreements, owners or operators of production field facilities typically control only the surface area necessary to operate the physical structures used in oil and gas production, and not the land between well drill sites."[70]

Those unique industry characteristics have been handled in various ways under relevant CAA programs. For example, Congress itself specified under the CAA § 112 air toxics program that "emissions from any oil or gas exploration or production well (with associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section."[71] Congress thus recognized the potential confusion that might arise as to how oil and gas production operations should be grouped for purposes of identifying and administering the CAA § 112 air toxics program and gave EPA detailed instructions for addressing such operations in a discrete, plant-like fashion.

Similarly, in the absence of such industry-specific direction from Congress under the CAA Title I preconstruction permitting programs and Title V operating permit program, EPA promulgated regulations directing that source determinations under those programs should focus on geographically discrete collections of equipment and operations. Under the Title V program ,a major source is defined as "any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties …)" and specifying that "[f]or onshore activities belonging to Standard Industrial Classification (SIC) Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1⁄4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment.".[72]

EPA took a different approach in Subpart W of the GHGRP. There, EPA observed that "[f]or some segments of the industry (e.g., onshore natural gas processing, onshore natural gas transmission compression, and offshore petroleum and natural gas production), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying the scope of reporting and responsible reporting entities."[73] But, consistent with EPA's experience under the air toxics and permitting programs, EPA observed that "in onshore petroleum and natural gas production and natural gas distribution such distinctions are more challenging."[74]

EPA concluded that "it was necessary to provide a unique definition of facility for each of these two segments in order to ensure that the reporting delineation is clear, avoid double counting, and ensure appropriate emissions coverage."[75] That "unique definition of facility" called for aggregation of all operations under common ownership or control within a given hydrocarbon basin.[76] While that broader Subpart W definition of "facility" served the unique, non-substantive information-gathering purposes of Subpart W, EPA cautioned that "[t]hese definitions

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[69] *Id*.
[70] *Id* at 2-3.
[71] CAA § 112(n)(4)(A)
[72] 40 C.F.R. Part 71.2
[73] 75 Fed. Reg. 74458, 74466-7 (Nov. 30, 2010).
[74] *Id*. at 74467.
[75] *Id*.
[76] *Id*.

are intended only for purposes of Subpart W and are not intended to affect the definition of a facility as it might be applied in any other context of the Clean Air Act."[77]

Notably, EPA issued the GHGRP primarily under the general information gathering authority of CAA § 114, which in relevant part authorizes EPA to obtain information from "any person who owns or operates ***any emissions source***," but does not otherwise explain what constitutes a "source" under that section. CAA § 114(a)(1) (emphasis added). Given the lack of any other CAA provision authorizing or governing the GHGRP, EPA's "facility" definition for the oil and gas sector in Subpart W is not necessarily applicable in deciding how "facility" (or functionally similar terms) should be defined under substantive CAA programs – including the WEC rule.

In sum, defining "facility" (or functionally similar terms) under the CAA is "challenging" in the oil and gas production sector given the unique nature of the operations and the wide geographic dispersal of interrelated operations. Under the substantive CAA programs (i.e., those that impose emissions limitations or standards), EPA is required or, for good and compelling reasons, has opted to adopt an approach that focuses on geographically discrete operations rather than aggregating interrelated operations dispersed over a wide geographic area. Conversely, under the purely informational GHGRP (a program that is not governed by any express CAA provision), EPA decided for program-specific purposes to aggregate operations at a basin level, with a caution that such an approach was "not intended to affect" how a facility is defined under other CAA programs.

That backdrop shows that there is an acute need to define the term "facility" when regulating the oil and gas sector under the CAA. That need is particularly pronounced here given that the geographic bounds of an "applicable facility" are not prescribed in CAA § 136 and there is no indication that the definition of "facility" used in Subpart W of the GHGRP must be applied. Moreover, it is not necessarily reasonable to assume or infer that the basin-wide definition of facility that EPA coined under Subpart W solely for purposes of facilitating the collection of GHG emissions information is appropriate under the WEC rule, which serves the very different purpose of imposing methane emissions fees in prescribed circumstances.

Yet, as noted above, EPA in the Proposed Rule does not describe the geographic boundaries of an applicable facility or otherwise acknowledge or discuss that important topic. EPA seems to assume that the Subpart W facility definition will apply under the WEC rule. But that tacit assumption does not provide the explanation needed to fully understand the Agency's factual, policy, and legal rationale on such a key element of the Proposed Rule.[78] As a result, commenters do not have adequate notice to develop informed comments. Also, for the same reasons, EPA has not satisfied its obligation under CAA § 307(d)(3)(C) to explain the "major legal interpretations and policy considerations underlying the proposed rule." Prior to finalizing the rule, EPA must provide further clarity as to the proposed bounds of an "applicable facility" and provide an opportunity for public comments on that proposal.

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[77] *Id.*

[78] For example, EPA explains in passing that "for certain industry segments a single reporting facility may represent operations in two or more industry segments." *Id.* at 5323. EPA proposes that, "[t]o accommodate for such facilities, we are proposing within the definition of "applicable facility" that such operations would be considered a single applicable facility under part 99." *Id.* But the proposal to combine emissions from multiple industry segments located within a single physical "facility" is at odds with the segment-specific definitions for the various facilities that must report under Part 98. See, e.g., § 98.238 (definition of "facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for corresponding subpart A requirements"). To allow for informed comments, EPA must explain why "applicable facility" under CAA § 136 should be different than a "facility" under Subpart W. Moreover, EPA asserts at several places in the Proposed Rule that, because Part 98 preexisted CAA § 136 and the WEC regulatory program, it should be presumed that Congress intended relevant provisions of Part 98 to be applied in the WEC program. See, e.g., 89 Fed. Reg. at 5328 (Part 98 was "an established program at the time that Congress drafted CAA section 136."). But when EPA must make changes to existing Part 98 provisions – such as the segment specific facility definitions – the fact that Part 98 preceded CAA § 136 has little bearing on implementation of CAA § 136.

7.2 EPA must consider all relevant factors when making regulatory decisions and did not provide analysis of how regulatory alternatives would affect the scope of applicability of the WEC.

A broader problem with the Proposed Rule related to these issues is the Agency's failure to consider three of the most important factors related to implementation of CAA § 136 – how the many decisions EPA must make in devising the regulatory program affect: (1) applicability of the WEC program (e.g., how many facilities will exceed the 25,000 tpy emissions threshold); (2) the number of facilities that trigger the obligation to pay a fee; and (3) for those owing a fee, the amount of that fee. Instead, EPA appears to have made an unstated assumption that it should maximize applicability of the WEC program and maximize the fees paid under the program rather than design the program to further incentivize emissions reductions. For example, as discussed, EPA proposes that netting should be allowed only at the subsidiary level and not among operators owned by a larger parent company and proposes that facilities with less than 25,000 tpy of emissions are not eligible to participate in netting. Those proposed provisions plainly would require owner/operators to pay more fees than Congress intended by excluding facilities from netting where emissions have been brought below WEC thresholds.

Also as discussed, EPA proposes numerous constraints on implementation of the regulatory compliance exemption, such that it would not become available until several years after the WEC rule becomes effective and would be virtually impossible for any applicable facility to achieve.

For each of these examples (and more broadly for other key program elements presented throughout the Proposed Rule as a whole) EPA provides no analysis of how the regulatory alternatives would affect the scope of applicability of the WEC rule, the number of entities required to pay, and the fees that would be due. EPA also fails to assess how the differing impacts on those critical program factors would affect overall program implementation. For example, EPA does not consider whether incentives to reduce emissions would be greater or lesser, whether differences in fee payments would be material, and whether the regulatory alternatives promote or detract from the overall program purposes and Congressional intent.

EPA, of course, is obligated to consider all relevant factors when making regulatory decisions.[79] ("Normally, an agency rule would be arbitrary and capricious if the agency … entirely failed to consider an important aspect of the problem."). EPA falls short of that obligation here by failing to assess the programmatic consequences of the key regulatory alternatives.

Lastly, we note that the Proposed Rule incorporates elements of Subpart W that EPA has proposed to adopt, but as of the date of these comments has not issued in a final rule.[80] Because the Subpart W amendments that EPA proposed for purposes of implementing the WEC program are not yet final, we have no opportunity to understand whether the not-yet-final Subpart W provisions will function appropriately under the WEC program. We thus are unable to provide informed comments on these important issues in the context of this Proposed Rule.

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[79] *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29 (1983) at 43

[80] See, e.g., 89 Fed. Reg. at 5374 (proposed § 99.20(c), requiring for "RY 2025 and later" the use of proposed § 98.236(aa)(3)(ix)).

8.0 Other General Comments

8.1 Facilities that do not sell natural gas should be exempt from the WEC.

EPA notes in the preamble to the proposed WEC rule that a number of gathering and boosting facilities exist that do not send gas to sale and, as a result, would report zero natural gas volumes used in the waste emissions threshold calculations and, therefore, all reported methane emissions would be considered to be exceeding the waste emissions threshold and subject to the fee. EPA asserts this, "is based on a plain reading of the statutory text." We disagree.

The statutory text at section 136(f)(2) reads:

> With respect to imposing and collecting the charge under subsection (c) for an applicable facility in an industry segment listed in paragraph (3), (6), (7), or (8) of subsection (d), the Administrator shall impose and collect the charge on the reported metric tons of methane emissions that exceed 0.05 percent of the <u>natural gas sent to sale</u> from or through such facility. [emphasis added]

A plain reading of this text conveys that gathering and boosting facilities that do not send gas to sale are simply not contemplated by the statute. EPA has invited comment on the prospect that all methane emissions from such facilities should be considered below the waste emissions threshold. We believe this is the appropriate and statutorily supportable approach.

It is inappropriate to charge such facilities fees in the absence of a threshold when such thresholds exist for other industry segments. Simply applying a waste emissions threshold of zero is both punitive to well designed and efficient gathering and boosting facilities not engaged in gas sales and in plain contradiction of the enabling statutory language.

8.2 Facilities under construction should be clearly defined as exempt under the WEC.

Facilities that are not yet producing any oil or gas for sale, but are in the process of being constructed, are not wasting methane or losing it as a result of routine operations, and therefore should not be assessed any fees during the construction period. Emissions that occur during this period are primarily combustion emissions associated with the drilling rig or other fuel combustion sources necessary for the construction. There will be minor amounts of methane generated during well testing prior to bringing the well online but those emissions are temporary, minor, and unavoidable.

EPA explains in the preamble that "the WEC provides an incentive for the early adoption of methane emission reduction practices and technologies" and that "Congress structured the WEC so that it focuses on high-emitting oil and gas facilities". EPA further highlights in the preamble that "Facility efficiency in terms of methane emissions per unit of production or throughput would have a large impact on the amount of the WEC owed, with more efficient facilities expected to have emissions falling below the specified thresholds". New facilities, which are focused on early adoption of methane emissions reduction practices during the design stage, do not benefit from the incentives intended by WEC. These new more efficient facilities are expected to have emissions falling below the specified thresholds after start-up and once production begins. However, during construction/pre-production years, they are unable to utilize the waste emissions threshold calculation to demonstrate that.

For these reasons, an exemption should be provided for facilities in pre-production phase that are designed with early adoption of methane emission reduction practices and technologies.

Alternatively, later reporting applicability could be considered for facilities in pre-production phase that are designed with early adoption of methane emission reduction practices and technologies, similar to treatment of delineation wells under Subpart W:

> "You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the well ID number(s) for the well(s) included in the number."

In this manner, the waste emissions threshold could be applied to the methane emissions that occur during the period of construction so that benefit is not lost and the well-designed facility is not penalized.

8.3 Comments on Confidentiality Determinations

EPA proposes that the name and contact information for the designated representative of the WEC obligated party are "emissions data" and therefore not confidential. We do not believe the personal contact information about personnel including the name, address and email should not be considered emissions data and available publicly.

8.4 Cross Reference and other Minor Clarifications

Below are some cross reference and other typographical errors we have identified within the proposed WEC regulatory text.

- 99.2 – proposed definitions of "gathering and boosting system" and "gathering and boosting system owner or operator" do not match the proposed revisions under Subpart W. Definitions should be aligned between Part 98 and Part 99.
- 99.31(a) – "§ 99.30(a) through (f)" should be "§ 99.30(a) through (e)".
- 99.31(b) – "paragraphs (b)(1) through (10) of this section" should be "paragraphs (b)(1) through (11) of this section".
- 99.31(b)(8) – "Nnatural gas" should be "natural gas".
- 99.32(b)(1) – References to Subpart W may need to be updated based on proposed Subpart W revisions.
- 99.41(c) – the word "requirement" is repeated, and the second instance should be deleted.
- Cross references to the regulatory compliance exemption may need to be clarified.
    - 99.7(b)(2)(iv) – "99.41" should be "99.42"; "99.40" might need to be "99.41".
    - 99.8(c)(2)(i) – "99.41" should be "99.42".
    - 99.8(d)(2) – "99.41(c)" should be "99.42(c)".
    - 99.21(c) – "99.40" might need to be "99.41".

- 99.21(d) – "99.40" might need to be "99.41".
- 99.22 – "99.40" might need to be "99.41".
- 99.40(c) – "99.41" should be "99.42".
- 99.40(d) – "99.41" should be "99.42".
- 99.41(a) – language appears inconsistent with 99.40(a). Reference to "99.21(d)" should be removed since that citation says that the regulatory exemption does not apply.

Attachment A

Previous API Comments on “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources” Oil and Natural Gas Sector Climate Review

(NSPS OOOOb and EG OOOOc)

Docket No. EPA-HQ-OAR-2021-0317

Letters Submitted

February 13, 2023 & January 31, 2022

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February 13, 2023

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W. Washington, D.C. 20460

Attention: Docket ID EPA-HQ-OAR-2021-0317

RE: Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Including Appendix K and Social Cost of Greenhouse Gases

Dear Administrator Regan:

The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (87 FR 74702, December 6, 2022) ("Supplemental Proposal"). This submittal includes comments on the associated Appendix K proposal and EPA's "Report on the Social Cost of Greenhouse Gases".

API is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. Gross Domestic Product (GDP). API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators, and marine transporters, as well as service and supply companies, providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

As we indicated in our comments on EPA's November 2021 Proposal (86 FR 63110, November 15, 2021), API supports the cost-effective, technically feasible, direct federal regulation of methane from new and existing sources across the supply chain. We appreciate EPA's further development of a fugitive emissions monitoring framework that allows for use of advanced detection technologies. We also appreciate EPA's recognition that Appendix K's monitoring protocol is not appropriate for the upstream production and transmission segments. While we appreciate EPA's responsiveness to many of the issues raised in our comments[1] on the November 2021 Proposal, nevertheless, we have serious concerns regarding the cost effectiveness, technical feasibility, and legal soundness of many aspects of the Supplemental Proposal. We also have extensive concerns with EPA's Draft Report on the Social Cost of Greenhouse Gases and the lack of transparency in the Interagency Working Group's process. Moreover, we strongly disagree with EPA's assertion[2] that November 15, 2021 can serve as the applicability date of the final rule for new, reconstructed, and modified sources.

Reducing methane emissions is a shared priority for EPA and our industry. We are committed to advancing the development, testing, and utilization of new technologies and practices to better understand, detect, and further mitigate emissions. In recent years, energy producers have implemented leak detection and repair (LDAR) programs, phased out the use of high-bleed pneumatic controllers, and reduced emissions associated with flaring – voluntarily and under federal and state regulations. Voluntary, industry-led initiatives such as The Environmental Partnership[3] have built on the progress industry has made to reduce emissions and continuously improve environmental performance. Since its founding in 2017, the Partnership has grown to include over 100 companies representing over 70% of total U.S. onshore oil and natural gas production.

The New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc are complex rules that will apply to hundreds of thousands of facilities owned and operated by these and other companies, including many facilities that have not previously been subject to regulation under the Clean Air Act. Because of the wide variety of conditions faced by these facilities, the novel nature of a first ever existing source rule, and timing of the Supplemental Proposal's release and subsequent overlap with the holiday season, API requested[4] an extension of the comment period to allow additional time for our staff and our members to fully review the Supplemental Proposal and provide EPA with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. As we noted, API members who are engaged on this issue have been concurrently engaged in reviewing additional recent legal and regulatory developments on this subject matter. We regret that EPA did not grant the request and may rush to completion of a final rule that does not reflect the full measure of consideration necessary to ensure cost effectiveness, technical feasibility, and legal soundness.

In our review of the Supplemental Proposal, API once again considered the effectiveness of emission reduction strategies, safety, feasibility, operability, and cost. Where appropriate, we have recommended changes to the regulatory text that will enable the final rule to meet these critically

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[1] EPA-HQ-OAR-2021-0317-0808
[2] 87 FR 74716
[3] http://www.theenvironmentalpartnership.com
[4] EPA-HQ-OAR-2021-0317-1588

important criteria. We have also detailed the necessity of workable implementation timelines that consider the supply chain and labor constraints facing our industry, constraints which will be exacerbated as the final rule takes effect. The adoption of the recommendations in our comments in the final rule would reflect a more cost-effective and technically feasible regulation of methane.

API appreciates EPA's engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize a cost-effective rule that incentivizes innovation, advances the progress made in reducing emissions and addressing climate change, and ensures that our industry can continue to provide the world with the affordable, reliable energy it requires.

If you have any questions regarding the content of these comments, please contact Ryan Steadley at steadleyr@api.org.

Sincerely,

cc:

Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Karen Marsh, EPA
Steve Fruh, EPA
Amy Hambrick, EPA

API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"

(Proposed NSPS OOOOb, EG OOOOc, Appendix K and the Social Cost of Greenhouse Gases)

Docket ID: EPA-HQ-OAR-2021-0317

February 13, 2023

Executive Summary

The American Petroleum Institute (API) supports certain aspects of the Supplemental Proposal for New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc and remains committed to working with the Environmental Protection Agency (EPA) and the Administration to identify cost-effective emission control opportunities. The comments provided herein focus on legal, technical, and feasibility challenges with specific provisions that EPA included within the Supplemental Proposal of NSPS OOOOb and EG OOOOc. Listed below are API's primary concerns with the proposed rules.

To facilitate review of our comments, API has summarized these concerns and provided reference to the detailed comments where additional supporting discussion has been included. Our members look forward to continued dialogue and engagement as EPA works towards finalizing these important rules.

1) **The Applicability Date for NSPS OOOOb should be December 6, 2022.**
   The Clean Air Act (CAA) Section (§) 111(a)(2) definition of "new source" uses the term "proposed regulations" in defining the new source trigger date. The November 2021 preamble alone cannot constitute a proposed rule any more than a final rule that is unaccompanied by regulatory text could be declared a "rule." Although the November 2021 preamble described the type of regulatory requirements that EPA contemplated promulgating, the preamble was not in and of itself a document that establishes the "agency statement of general or particular applicability and future effect." That type of required statement would be established only by the proposed regulatory text, which was not provided until the December 2022 Supplemental Proposal. Many of the requirements included in the proposed regulatory text could not have been gleaned from the prior descriptions provided. Refer to Comment 8.1 and Comment 12.1.

2) **Adequate implementation time must be provided for NSPS OOOOb and EG OOOOc.**
   NSPS OOOOb and EG OOOOc will apply to hundreds of thousands of sites when implemented. Our members are already experiencing a noticeable delay in the supply chain for equipment required by the proposed rules including (but not limited to) control devices, flow monitoring equipment, instrument air systems, solar panels, etc. Control devices are currently experiencing delays of 3 to4 months, while flow monitors are on backorder for a minimum of 6 to8 months from suppliers. Instrument air systems (including the air compressor and associated equipment) are nearly 1 year on backorder, and recently ordered solar panels are delayed between 18 to24 months. As more facilities become subject to proposed requirements in NSPS OOOOb and EG OOOOc, the above timelines are anticipated to be exacerbated before the market experiences a correction to meet these new levels of demand. We provide more detail related to current supply chain delays in Comment 5.2 and Comment 7.1. We request EPA consider these challenges prior to finalization of certain provisions within these rules to allow operators the ability to acquire and install the required equipment. Additionally, EPA should allow more time for new, modified, and reconstructed sources to come into compliance with NSPS OOOOb if it maintains the current applicability date of November 15, 2021.

3) **Associated gas provisions need to be significantly modified.**
Whereas API supports and recognizes the environmental benefit of eliminating the venting of associated gas from oil wells, EPA must recognize the distinction between associated gas from oil wells that route to a sales line and oil wells that do not have adequate or accessible gas gathering infrastructure. Removing wells connected to sales lines (or recovering gas for another primary purpose) from the requirements of the associated gas provisions would help to eliminate confusion resulting from EPA introducing its own interpretation of "flaring" when multiple definitions of "routine flaring" already exist in state and voluntary programs. Additionally, API does not support the requirement to make an infeasibility demonstration, along with safety and technical certifications in order to flare associated gas. Refer to Comment 4.0. and Comment 12.9.

4) **As proposed, the Super-Emitter Response Program presents numerous legal, logistical, commercial, safety, and security risks that have not been adequately considered by EPA within the Supplemental Proposal.**
To address these concerns (and assuming EPA resolves the legal deficiencies), numerous adjustments to the proposed framework are necessary. Specifically, EPA must establish requirements for monitoring of third-party data, provide a formal notification process that includes EPA involvement and review, and provide limitations on how any monitored data is released and used publicly. Refer to Comment 1.0, Comment 12.3, and Comment 12.4.

5) **In determining storage vessels affected facility Potential to Emit, EPA's proposed criteria for legally and practicably enforceable limits have broad legal implications and pose several permitting challenges.**
The proposed criteria and the additional methane emissions threshold may be lacking in existing permits that have previously been understood to be legally and practicably enforceable and may also be impossible to obtain under existing permitting mechanisms. EPA should continue to defer to the states on sufficient monitoring, recordkeeping, and reporting requirements to include in permits to establish legally and practicably enforceable limits. API also offers suggestions concerning various definitions and proposed control requirements for storage vessels affected facilities. Refer to Comment 6.0. and Comment 12.10.

6) **As proposed, alternative technology requirements for fugitive emissions monitoring, including continuous monitoring, are impractical and may disincentivize the use of this emerging technology.**
API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA to make key adjustments in the final rule to enhance the use, and not unintentionally disincentivize development and deployment of these technologies. In particular, we believe there should be approved technologies for operators' use at the time the rule is finalized, alternate technologies should not be held to a greater level of stringency (i.e., frequency) than Best System of Emission Reduction (BSER) as currently proposed, and EPA should streamline the timeline and actions to conduct repairs. Refer to Comment 3.0.

7) **API proposes AVO inspections only at multi-wellhead only sites.**
EPA's focus on finding large fugitive emissions at single wellhead only sites using audio, visual, olfactory (AVO) inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall

well site emissions. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Refer to Comment 2.1.

8) **EPA should clarify its preamble language concerning leaks detected from a cover or a closed vent system during associated inspections or other fugitive emissions monitoring.**
Emissions detected from covers and closed vent systems do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented. Like standards for other fugitive emissions components, the "no identifiable emissions" standard is a work practice standard rather than a numerical emissions standard. Therefore, EPA must make it clear that a cover or closed vent system remains in compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed. Regarding control devices, API recommends a compliance extension of at least one year for the proposed monitoring requirements. We also offer suggestions to provide consistency between manufacturer-tested devices and other enclosed combustion devices as well as request EPA provide the necessary monitoring alternatives given the increased number of control devices subject to proposed monitoring requirements. Refer to Comment 5.0.

9) **EPA should amend many of the provisions within the Supplemental Proposal to work practice standards and eliminate the additional technical demonstrations with accompanying certification statements.**
EPA has added several certification statements throughout the proposed requirements for NSPS OOOOb and EG OOOOc – including certifications for pneumatic pumps, gas well liquids unloading operations, and associated gas from oil wells. EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating exceptions that require technical demonstrations and engineering certification. Inclusion of these technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA § 111 because non-emitting standards are not "adequately demonstrated" if exceptions are needed to make them feasible and workable. Regarding the certification statements themselves, a certified official is already required to sign the report certifying the company's compliance with all applicable provisions. These additional certifications should be removed prior to finalization of these standards for associated gas from oil wells, pneumatic pumps, and gas well liquids unloading operations. Refer to Comment 4.1, Comment 8.2, Comment 9.1, Comment 10.1, and Comment 12.9

10) **Requirements for pneumatic controllers and pneumatics pumps should be simplified and aligned.**
While we support EPA's proposal for defining the affected facility for both pneumatic controllers and pumps as the collective, we have numerous concerns with the practical and logistical aspects of how EPA has outlined control standards between the two sources. Specifically, EPA has proposed a completely distinct set of requirements for natural gas-driven controllers separate from natural gas-driven pneumatic pumps with sometimes conflicting statements made to justify EPA's decisions. The requirements for both pneumatic controllers and pumps should be streamlined for consistency with neutral technology standards that do not require additional certifications and allow for emissions to be routed to a control device. Refer to Comment 7.0 and Comment 8.0.

11) **EPA should streamline the recordkeeping and reporting requirements associated with compliance assurance of the proposed rules.**
EPA should continue to streamline both recordkeeping and reporting as it relates to these proposed requirements to include only the necessary information that will help assure compliance. Streamlining is especially critical for locations with existing sources as the cumulative impacts for tracking records are anticipated to be much larger than EPA estimates and will apply to hundreds of thousands of sites across the U.S. For some sources, EPA has described requiring records and potential reporting of information that does not link directly to emission controls or work practices, which API does not support. We support inclusion of recordkeeping and reporting that help demonstrate compliance with less administrative burden. Refer to Comment 9.3 and Comment 13.2.

12) **EPA should grant equivalency for state programs across emission sources for NSPS OOOOb and EG OOOOc.**
Given EPA has described many requirements that are consistent with those at the state level (e.g., Colorado, New Mexico, and California), EPA should allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb and EG OOOOc where it is appropriate to do so for leak detection and repair (fugitive emission monitoring) and other emission control provisions. EPA should allow states the opportunity to demonstrate programmatic equivalency, including addressing deviations from the form of the proposed standards. Without this, states and operators may be administering and complying with two sets of requirements (standards and administrative) that are duplicative because they are intended to achieve similar goals but are not perfectly identical. It also precludes innovative regulatory approaches from states. Refer to Comment 12.6 and Comment 12.7.

13) **EPA should carefully consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc in conjunction with the cumulative burden imposed through provisons in the Supplemental Proposal.**
EPA must consider the cumulative burden imposed to the regulated community of numerous and onerous provisions in the Supplemental Proposal, especially due to the unprecedented number of sources that will be subject to the rule given the proposed November 2021 applicability date for new, modified, and reconstructed sources. EPA must also consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc and the difficulty the industry has faced to fully understand the impacts of this rule without a comment extension. These difficulties for the regulated community have been compounded by other rules that impact the same sources (e.g., Bureau of Land Management's (BLM's) Waste Prevention Proposal). Specifically, EPA needs to be clear on the disposition of NSPS OOOO and OOOOa applicable sources if and when they become subject to EG OOOOc. Finally, EPA must revise its Regulatory Impact Analysis, including the potential for lost production stemming from implementation of these rules. Refer to Comment 12.1 and Comment 12.5.

14) **For equipment leaks at onshore natural gas processing plants, API recommends that closed vent systems be monitored annually and that appropriate VOC and methane concentration thresholds be established for applicability.**
While API supports the proposed bimonthly OGI monitoring as well as the proposed alternative monitoring based on the incorporated NSPS VVa requirements with simplifications, we have concerns with the proposed frequency for closed vent systems and the proposed potential to emit applicability threshold for VOC. While we generally support the proposed Appendix K for OGI monitoring at gas plants, we have several comments regarding proposed Appendix K as provided in Attachment A. Other

comments on leak detection and repair at gas plants include our recommendation on the proposed definition of equipment for capital expenditure evaluations. Refer to Comment 11.0 and Attachment A.

15) **API appreciates EPA's decision to accept comments specifically on the EPA's Social Cost of Greenhouse Gas (SC-GHG) Report, but we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates.**
API shares the Administration's goal of reducing economy- wide GHG emissions. With respect to SC-GHG our concerns stem from the approach taken by EPA, including the anticipated role of these new estimates in EPA's rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group. Refer to Comment 13.5 and Attachment B.

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List of Attachments

Attachment A – Responses to EPA Solicited Comments for Use of Optical Gas Imaging in Leak Detection

Attachment B – Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

PROPOSED NSPS AND EMISSIONS GUIDELINES FOR THE OIL AND NATURAL GAS SECTOR (NSPS OOOOb AND EG OOOOc) INCLUDING APPENDIX K

DOCKET ID: EPA-HQ-OAR-2021-0317

While we have made every effort to thoroughly review both proposed New Source Performance Standard (NSPS) OOOOb and Emission Guidelines (EG) OOOOc as we formulated these comments, there may be places where we only provide a citation or reference as it pertains to proposed regulatory text in NSPS OOOOb. Unless we have provided a distinctly separate comment as the topic pertains to EG OOOOc, we also intend the comment to apply to proposed EG OOOOc. Additionally, when using the terms "proposal" or "standards" in these comments in reference to the November 2021 preamble, it does not constitute a "proposed rule" or "emission standard" for purposes of triggering applicability under CAA § 111(a)(2).

1.0 Super Emitter Response Program

As proposed, the Super Emitter Response Program (SERP) presents numerous legal[5], logistical, commercial, safety, and security risks that have not been adequately considered by the EPA and are the basis for the comments we offer herein. These complex issues would benefit from further discussions between EPA, operators, and other interested parties.

Our members understand the importance of identifying and addressing large emissions events and any future support for a program would be grounded in a shared interest to reduce the incidence of these emission events. For over three decades, EPA and industry have successfully collaborated on the implementation of voluntary programs to reduce methane emissions from the oil and natural gas sector under both the Natural Gas Star and Methane Challenge Programs. While we believe the SERP may be better suited to function as a voluntary based program, API members recognize the intent of the EPA to create a useable and workable program that identifies these large emissions events from a variety of stakeholders.

We encourage EPA to conduct additional outreach on the proposed framework and repropose a program that meets all Clean Air Act legal requirements prior to finalizing the requirements (as provided in §60.5371b). Our members would welcome the opportunity for future discussions on this important topic.

1.1 API proposes a programmatic framework that is managed by EPA and incentivizes the finding and subsequent repair of potential super emitter emission events.

EPA has described the SERP as a backstop to the requirements of NSPS OOOOb and EG OOOOc. However, as we describe throughout our comments there are serious legal, logistical, commercial, safety, and security problems inherent in EPA's proposed program. The framework we have described herein achieves the goals EPA has described for the program while addressing the concerns API members have with EPA's proposal.

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[5] See Comment 12.3 and 12.4 of this letter for a discussion of the numerous legal deficiencies underpinning the proposed SERP.

For the SERP to be effective, EPA must reconsider the operational flow of how the program will function and be implemented. This framework includes adding formal notifications first from third parties to EPA and then from EPA to operators. We also specifically offer suggestions on clear timelines for all participants of the program where information can be transferred in a clear and transparent order, which we have emphasized in our framework.

Below we have outlined our suggestions on the appropriate steps to be included in a reproposed framework, which provides greater confidence that the data provided under the program will be valid, actionable, and achieve EPA's goals for transparency within the program.

1) The third party completes approval certification process by EPA for inclusion in the Super-Emitter Response Program and becomes "certified or re-certified".
2) Certified third party[6] notifies EPA of planned monitoring, including submittal of a monitoring plan, at least **30 business days** prior to planned monitoring. Depending on technology deployed, such as satellites, this pre-approval may include flight plans for extended time periods. The components of the monitoring plan are more fully described in Comment 1.1.3 of this letter.
3) EPA reviews the certified third parties' monitoring plan for approval or disapproval.
    a. If approved, EPA notifies the impacted operators at least **7 business days prior** to monitoring with details of the monitoring to be conducted including technology planned for use, dates of monitoring, flight paths (if appropriate), etc. This notice essentially acts as a "pre-notification" to operators, which enables the operator to have staff available to ensure safety of operations, if warranted based on technology that will be used to detect potential emissions by a third-party.
    b. This "pre-notification" may also help both EPA and the third-party identify the appropriate operators, including the correct contact information, in the event a super emitting emissions event is detected. The potential for incorrect identification of operators is of concern for our members.
4) Timing of notification of results of monitoring to the operator is critical to the effectiveness of the SERP. After monitoring is completed, third party has **2 calendar days** to provide data as defined in §60.5371b(b) to the EPA.
5) If EPA determines the data provided by the third-party to be credible and warrants investigation, EPA provides data for any super emitter emission event to the appropriate operator(s) within **3 calendar days** of verification of third-party monitored data.[7]
6) Operator(s) will initiate an investigative analysis **within 5 business days** of receipt of data from EPA and complete the investigation within **10 business days** of receipt of the data from EPA.
    a. Given how certain technology is applied, the detection may not be from the facility that was notified, may be a permitted release, may be due to maintenance activity, or another reason that does not require action (such as monitoring data calibration issue). If the emissions event was the result of a permitted activity or could not be validated after full investigation by the operator, the

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[6] For the purpose of these comments when we reference a 'third-party', "certified notifier" or 'certified third-party' we mean the certified individual and the monitoring company whose technology is utilized to conduct monitoring.

[7] The basis for the timing proposed in steps 4 and 5 is to align with what EPA has proposed for operators using similar technology.

operator will provide "no action required" demonstration to EPA as specified in §60.5371b(c)(8) and §60.5371b(e)(1).

   b. If the emissions event was result of component failure or other equipment defect, the operator(s) will complete final repairs **within 15 calendar days** after completing the investigative analysis.

7) All public information should be published by EPA only. EPA should manage all data that is to be public and establish a protocol for when and what type of specific details of a potential super-emitter emissions event is published via EPA's proposed website per §60.5371b(e)(4). We strongly disagree with the assertion in Section IV.C.2.a of the preamble (87 FR 74750) which states "*The EPA would then promptly make such reports available to the public online. Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting."* Given that much of the data collected can be interpreted incorrectly and not aligned with operating conditions, the EPA should be the only authority to publish data, and EPA should publish data only after operators have had an opportunity to review and respond to the information and EPA has fully reviewed and vetted follow-up actions with the operator.

The timing of each step in the above framework has been crafted with the intent that all participants are held to timelines that are workable and suitable for each step of the framework. Operators are concerned they could receive multiple third-party notifications with limited time and resources to respond appropriately if stricter timing criteria for third parties to provide data is not established. The above framework seeks to address this concern.

1.1.1 EPA should establish transparent certification requirements for third-party monitoring.

Two-way accountability will allow for efficient and effective execution of the super-emitter response program. EPA should develop a clear set of criteria (e.g., in a checklist form) that any certified third-party would need to meet to participate in the program. This certification is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. We appreciate the demonstration for third-party notifiers as outlined in the preamble (87 FR 74750), but do not believe the requirements as proposed in §60.5371b(a) provide enough stringency. Considering the requirements EPA has established for an operator, the same level of scrutiny should also be expected of the third-party data provider when using the same technology. Strict criteria should be established covering the following:

- An expectation from EPA that third parties and their approved detection technologies must be re-certified on a specified frequency. This certification process should be similar to other EPA certifying programs (e.g., EPA auditor).

- An expectation for third parties to attend EPA-specific training, including the do's/don'ts as well as what they are authorized to do or not do – including the handling of data they plan to use within the program.

- Clear criteria for what type of actions may immediately make data collected invalid and/or fully revoke a third party's participation in the program. Regarding EPA's proposed revocation of third party certification (87 FR 74750), we recommend that the criteria for revocation explicitly state that upon a third party's third submission of verifiably false data from any combination of operators or sites, or upon trespass or otherwise unlawful or unauthorized entry to a facility, or vandalizing energy infrastructure, or upon unauthorized distribution or publication of data gathered under the program, the offending third party

shall have their certification revoked for a period of no less than three years. Any data gathered at the time of a trespass would render that data invalid.

1.1.2 The super emitter response program must have a transparent and formal notification process where EPA manages the flow of information from the third-party to the operator.

As similarly done with other EPA programs, formal notification to facility owners/operators (and even with the third-party) could potentially be via email or a central online-based system.[8] The process should allow EPA to confirm that the correct operator received the notification and follow-up if the operator does not respond within a certain timeframe. There are also concerns with measurement of emission events, including pin-pointing sources or facilities correctly (especially when there are adjacent facilities in proximity to each other or sharing boundaries), and in conjunction with the minimum resolution of the monitoring technologies.

Some additional considerations include the following:

- **Operators should be given advanced notice of planned third-party activity. As proposed, the response burden for operators is not predictable and operators are unable to properly plan and schedule resources.** If timing and location of surveys are unknown to a facility owner/operator, operators will have no indication of when and how much resources to have available. This is important to promptly evaluate data and implement corrective action if necessary. Third parties may employ technologies, like aerial surveys which can result in multiple detections in a short amount of time. It's not unreasonable to expect that surveys may be conducted by multiple third parties simultaneously or in series, and conversely, there could be extended periods of no third-party activity. Program requirements must balance the needs of operators to plan for both day-to-day operations and promptly prepare for and respond to third-party activity.
- **Detections of potential super-emitter emission events should be shared with the operator within a certain time period from detection to allow for effective and prompt response to reduce the emission impact.** As proposed, third parties only have to provide data "*as soon as practicable to the owner or operator*" under §60.5371b(b)(7). Since there could be many days between when monitoring occurred and when an operator receives the survey data, an investigative analysis may not find any significant ongoing / persistent emissions event. Furthermore, third-party notifiers could attempt to overwhelm a single operator with a rush of data from multiple monitoring campaigns (e.g., using remote-sensing equipment on aircraft) that would be untenable to fully investigate.

We propose suggested timing for these notifications in Comment 1.1.

1.1.3 Monitoring conducted by a third-party should be pre-approved and accepted by EPA prior to execution of the data gathering event.

There are clear protocols, including monitoring plans, that operators are required to have in place to conduct emission monitoring data. Any certified third party that conducts monitoring must be held to the same stringency

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[8] If an online-based system is chosen, there will be an additional resource / cost burden on EPA to develop and maintain the functionality of the system. Also, there may be an issue when operators are in close proximity to each other and have shared property boundaries, or when a facility was owned by a specific operator at one time but has been sold to another owner.

as an operator if they were to use the same technology. This reciprocity is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. It also is necessary, given that third-party monitoring would create enforceable legal obligations for affected/designated facilities as currently proposed. There is nothing under the law that, in and of itself, prevents any third party from conducting remote monitoring (as noted elsewhere, the law may impose restrictions on where/when/how such monitoring may be done; for example, third-party monitors may not trespass on private property). But when such monitoring has regulatory consequences, it would be arbitrary and fundamentally inconsistent for EPA to set more lenient criteria on third-party monitors than it does for similar monitoring required to be conducted by affected/designated facilities.

At least 30 business days in advance of the planned monitoring campaign, the third-party must submit a monitoring plan to the EPA for approval. The monitoring plan submittal should include the following information (at a minimum):

- Site coordinates and/or map of the area to be monitored;
- Description of monitoring equipment to be used to conduct the activity;
- Documentation of emissions detection limit;
- Proposed starting date and duration of the monitoring activity;
- Contact details (e.g., name, phone number, title) of third-party contact person;
- Name and details of owner of remote monitoring equipment;
- Quality assurance / quality control plan, including calibration procedures, if applicable to the technology (Subsequently, the third-party should also have to demonstrate how it met its monitoring plan for each monitoring event when monitored data is submitted to EPA);
- Specification on how the data will be provided and in what timeframe to the EPA; and
- Certification statement signed by an authorized company official attesting that the third-party will conduct monitoring activities in accordance with EPA requirements.

With the 30-day approval period, it would also allow EPA sufficient time to provide affected facility owners / operators notice of the upcoming monitoring event, which should be provided at a minimum 7 business days prior to the start of the monitoring field event.

1.1.4 There are safety and security concerns with third parties trespassing on private property.

Even though EPA notes in Section IV.C.2.a of the preamble (87 FR 74749) that it considered concerns for the safety of individuals engaged in third-party monitoring and of facility operator personnel, there are still tangible safety concerns related to the use of certain monitoring technology by third parties (e.g., mobile monitoring platforms) to identify super-emitter emissions events. Some operators have experienced public individuals driving through operator sites (especially in remote locations with no “fencing”) with vehicle mounted monitoring devices, which is especially problematic as access can typically be obtained by road, some of which may be private

roads. There have also been issues acknowledged between private third-party landowners and trespassers, which can be another point of contention.

Personnel working at our facilities are required to undergo numerous hours of training to safely perform their work duties, including but not limited to wearing the correct personal protective equipment based on site conditions, exposure to extreme heat or cold weather, biologic hazards such as snakes or other critters, specific training on how to navigate rotating equipment, and where and how to identify hazardous chemicals/gas. For example, training specific to the presence of hydrogen sulfide (H_2S) includes hazards, symptoms of exposure, detection devices, and how to safely walk away from exposure.

Individuals require site specific training to be present at any given facility and there is potential liability (to both the individuals and to company assets) for individuals who do not have this training. The proposed SERP framework is geared to remote technologies, which by their nature should in no way necessitate third-party representatives to appear at facilities. API recommends that any information that is collected by a third party that is outside of an EPA-approved monitoring campaign, where EPA and/or operators have not been notified in advance of the data gathering campaign, be considered invalid. As we also provided in Comment 1.1.1 , trespassing (such as driving through a site) should immediately result in revocation of a third party's certification and render any information gathered at the time invalid.

1.1.5 The EPA should clearly manage how third-party monitored data is published in conjunction with corrective actions taken by operators.

Participation in the regulatory process through the super-emitter response program by EPA-certified third parties must include limitations on the ability of those third parties to use the information gathered under the program for any other purpose. Such limitations must include requirements that the third party (and the monitoring companies they contract) maintain the security and confidentiality of data collected during SERP monitoring, where the monitoring results cannot be independently published (via website or social media). EPA has a fundamental role to play in the validation of third party collected data, which extends to the publication of such data. When a third party accepts the responsibility of participating as a certified notifier, they accept this role and handling of data.

- **Monitored data should not be published without context from operator feedback or corrective actions.** EPA's state within the preamble (87 FR 74750) "*owners and operators would have the opportunity to rebut any information in a notification provided by the qualified third parties in their written report to the EPA, by explaining, where appropriate, that (a) there was a demonstrable error in the third party notification; (b) the emissions event did not occur at a regulated facility; or (c) the emissions event was not the result of malfunctions or abnormal operation that could be mitigated.*" While we agree with this concept, the proposed framework does not provide the same level of assurance that these rebuttal statements would be linked to the third-party monitored data directly in the public forum without EPA intervention. If the data is posted on other public websites, there is a chance any resolution/follow up comments and descriptions from operators will not be carried over to the non-EPA sites, therefore resulting in inaccurate presentation of the facts. While we concur that data transparency is valuable, and share the goal of disseminating information to mitigate emissions events, these goals must be balanced with adequate considerations for national security risks, reputational risks (e.g., incorrect operator maligned in media, third party is not approved or certified by EPA, permitted events are taken out of context, etc.), and stakeholder risks.

- **EPA should establish a protocol or annual publication updating on progress of the program.** We believe the current language proposed in §60.5371b(e)(4) establishing a new EPA website is extremely flawed and ambiguous. Third-party monitored data on its own will provide very limited context for the general public and can be easily taken out of context. We believe a synthesized annual report or fact sheet published by EPA would offer a clearer depiction of relevant details with full context around super emitters including but not limited to: how many third-party monitoring events took place, the number and location of valid super emitter emission events that were detected, the number of super emitter events that were permitted or authorized emissions, the rate of erroneous notifications and the types of corrective actions that were taken to repair other super emitter emissions identified. Operator related information could remain anonymous in this annual report, unless EPA found specific operators to be conducting insufficient corrective actions or operators that do not acknowledge EPA's notification attempts regarding the monitoring campaigns (and EPA has verified the correct operator and contact information).

  At a minimum, EPA should limit the information for super-emitter emissions events so that the information cannot be misconstrued or used to publicly attack operators in the media; especially operators who are proactive participants within the SERP. The shared goal of finding these leaks and fixing them as expeditiously as possible should remain at the forefront and in conjunction with transparency objectives.

1.1.6 An "investigative" analysis should be conducted in conjunction with initial corrective actions.

As we explain further in Comment 3.2, the EPA outlines in §60.5371b(c) specific actions to take place if a super-emitter emission event occurs. API supports investigating the source and cause(s) of significant emissions events that are brought to an operator's attention Through the process described in our comments. We agree that EPA's investigative actions listed §60.5371b(c) are appropriate and practicable as far as investigating and conducting initial corrective actions for super emitter events. However, EPA's use of the term "root cause analysis" is problematic and ambiguous. The concept of "root cause analysis" is embedded in numerous other regulatory and non-regulatory programs and has varied meaning and purpose in each application. Thus, use of that term here does not clearly and adequately define the scope of the legal obligation, which will make it difficult for operators to understand what must be done to comply and will invite dispute and controversy if/when this program is implemented. To address this concern, we recommend the actions EPA has outlined be maintained, but the term supplied as the definition for those actions be changed to "investigative analysis" as it relates to super-emitters in §60.5371b(c).

1.1.7 After an investigative analysis has occurred, an operator should have the ability to designate the emission event as "no action required," as applicable.

Since the source of an emission detection during a monitoring campaign could be the result of various situations (and even EPA acknowledges that there may be demonstrable errored data), API suggests that the EPA include a pathway for operators to simply identify situations where "no corrective action required" beyond what has been proposed in §60.5371b(e)(1). These additional situations could include 1) the wrong operator was notified; 2) where the emission event cannot be validated by the operator; 3) there was a demonstrable error in the third-party notification; (4) the emission event did not occur at a regulated facility (e.g., well site or compressor station); or 5) the emission event was authorized as authorized or permitted operations. The information an operator should submit back to EPA should be simplified for planned or authorized emissions. Further, within

§60.5371b(e)(1)(iii), EPA must clarify that the applicable standard is limited to the applicable standard of this subpart.

1.1.8 Safe Harbor for Operators

The presence of a super emitter emission event does not necessarily indicate a standard has been exceeded or that a violation has occurred. Moreover, any documents shared with EPA articulating corrective actions taken should be subject to a safe harbor provision that prevents EPA or any other entity from using the information in the document for purposes of enforcement / notice of violation (NOV), civil suit, etc.

1.1.9 The role of states as a delegated authority within the super emitter proposed framework is unclear.

Throughout the preamble EPA uses language that mentions state agencies as delegated authorities. One such example is found at 87 FR 74750, *"The EPA further proposes that the entity making the report shall provide a complete copy to the EPA and to any delegated state authority (including states implementing a state plan) at an address those agencies shall specify."* The role of state agencies within the SERP must be more adequately defined. For example, as explained in these comments, the SERP program is not lawful or practically workable unless EPA takes a direct role in implementing the program (e.g., EPA must review and approve site-specific third-party monitoring plans, EPA must receive and vet the results of third-party monitoring and must decide whether the results are actionable). In the final rule, EPA must explain the process and degree to which these functions may reasonably be delegated to the states and, for functions that EPA determines are delegable, provide mechanisms to assure consistency among EPA's and the delegated states' programs.

2.0 Fugitive Emissions at Well Sites, Central Production Facilities and Compressor Stations

API supports the retention of NSPS OOOOa requirements for optical gas imaging (OGI) monitoring at well sites, central production facilities, and compressor stations. Except for multi-wellhead only well sites (see Comment 2.1), API also supports the proposed audio, visual, and olfactory (AVO) and OGI monitoring frequencies. In addition to the following comments concerning requirements for fugitive emissions at well sites, central production facilities, and compressor stations, API notes that EPA is not providing a meaningful opportunity to comment on a key basis for removing the wellhead only exemption because the underlying data for the Department of Energy (DOE) study[9] is unavailable.

2.1 API proposes AVO inspections only for all wellhead only sites.

EPA's focus on finding large fugitive emissions at single wellhead only sites using AVO inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. As EPA has already concluded, AVO inspections are a useful tool at

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[9] Bowers, Richard L. Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859

sites that lack extensive background noise and have field gas containing mixtures of methane and VOCs and condensate or produced liquids (87 FR 74727)[10]. Not only do wellhead only sites match these criteria, but their emission points are closer to ground level compared to other sites. For these reasons, out of all well site configurations, AVO is expected to perform the best at wellhead only sites, and it generally can be applied more frequently than other leak detection methods. EPA appropriately concluded that *"the types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspection"* (87 FR 74729)[11]. Given the large number of wellhead only sites and EPA's focus in regulating fugitive emissions at these sites, quarterly AVO inspections are appropriate to detect fugitive emissions at any wellhead only site including single wellhead or multi-wellhead well sites.

The proposed leak detection method and frequency for any emission source should take into consideration the count and relative magnitude of emissions, among other factors. The number of wellhead only sites across the U.S. is estimated to be in the tens of thousands. The resource demand from any leak detection requirement on wellhead only sites using OGI or Method 21 quickly multiplies.

EPA notes that the DOE study "*demonstrates that fugitive emissions do occur from wellheads, and in some cases can be significant"* as the basis for regulating wellheads. Similarly, commenters indicated "the wellhead itself is a source of emissions" because "these well sites have other smaller equipment that leaks and malfunctions, with large emissions having been observed from these sites". While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall well site emissions. A study conducted over the Permian Basin determined that simple sites, such as wellhead only sites, experience median emission rates two orders of magnitude smaller than complex sites (0.03 kg/hr for simple sites vs 2.6 kg/hr for complex sites)[12]. CAMS contracted with Bridger Photonics to conduct aerial surveys performed in the Permian Basin (5,361 pieces of equipment on 1,450 facilities over 250 square miles). The project found that 2% of total detected emissions were from wells and 5% of total detections were from wells[13].

These studies demonstrate that the population average emissions from wellheads is not relatively significant and therefore chasing fugitive leaks from these sources will not be impactful compared to deploying resources to other contributing sources. Nevertheless, we recognize this does not preclude the potential for fugitive emissions from an individual wellhead. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Coupled with proposed requirements[14] for conversion to non-emitting pneumatic controllers at existing sites, the increased cost of additional OGI screening at these sites raises further concerns regarding premature shut-in of production and states' ability to preserve the remaining useful life of facilities.

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[10] On the other hand, AVO inspections are a useful tool for identifying when there are indications of a potential leak without the need for expensive equipment or specialized training of operators. For example, at sites that lack extensive background noise, a person would be able to hear if a high-pressure leak is present, which could present as a hissing sound. Field gas produced at well sites contains a mixture of methane and various VOCs, which have the potential to be detected by smell. Where the field gas contains a lot of condensate or other produced liquids, any resulting leaks would present as indications of liquids dripping or potentially puddles forming on the ground.

[11] The types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspections and would not require the use of OGI for identification. Therefore, the EPA evaluated a periodic AVO inspection and repair program for addressing fugitive emissions from single wellhead only well sites.

[12] Robertson, Anna M., 2020, New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, Environmental Science and Technology, 54(21), 13926-13934 https://pubs.acs.org/doi/10.1021/acs.est.0c02927

[13] https://methanecollaboratory.com/wp-content/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021_vFinal.pdf

[14] See Comment 7.0

EPA's basis for applying OGI to multi-wellhead only sites is centered around additional connection points and valves with generally smaller emissions (87 FR 74732)[15]. While this basis is true, the focus appears to be misguided. If the principal concern with a single wellhead only site is to find the rare, but possible, large emissions leak, then it should follow that the principal concern for a multi-wellhead only sites should also be the rare occurrence of large emission leaks because it is relatively more likely with more than one well-head. That is, what warrants more attention to a multi-wellhead only site should not be the potential for more small emission leaks, but the greater potential for a large emission leak. Any significant difference in emissions leak potential from a single wellhead only site versus a multi-wellhead only site is not likely to be because of a small emission leak.

More frequent monitoring may also be challenging since many existing wellhead only sites can only be reached on foot due to remote location and lack of lease road access. While we believe quarterly AVO is the appropriate frequency for all wellhead only sites, at a minimum, bimonthly AVO inspections only would also be acceptable as the monitoring requirement for multi-wellhead only sites.

2.2 The proposed definition of fugitive emissions component requires further clarification.

Several aspects of EPA's proposed definition of fugitive emissions component require further clarification.

- **In yard piping should not be included in the definition of fugitive emissions component.** The inclusion of in yard piping as a fugitive emissions component expands that definition in unprecedented ways. Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.[16]
- **Definition should include thief hatches or other openings on a controlled storage vessel only.** Monitoring thief hatches and other openings on uncontrolled storage vessels adds no environmental benefit since the storage vessel emissions will be the same whether they are emitted from the tank vent or through thief hatches or other openings. Combined with the next item, fugitive emissions component should include thief hatches or other openings on a controlled storage vessel that is not subject to NSPS OOOO, OOOOa, or OOOOb because of a construction/reconstruction/modification date on or before August 23, 2011, or a legally and practicably enforceable limit.
- **Definition should also include the appropriate references to NSPS OOOO and OOOOa.** As proposed, fugitive emission components include covers and closed vent systems and openings on storage vessels not subject to NSPS OOOOb requirements. Since EG OOOOc will be implemented over the coming years, the definition of fugitive emissions component should also include the appropriate reference to

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[15] Multi-wellhead only well sites. For wellhead only well sites with two or more wellheads, the EPA anticipates that the same large emissions source (i.e., surface casing valves) would be present. In addition to these valves on the wellheads have additional piping, and thus connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO.

[16] We note that EPA's rationale for adding yard piping to the definition of "fugitive emissions component" is that, "[w]hile not common, pipes can experience cracks or holes, which can lead to fugitive emissions." 87 Fed. Reg. at 74723. EPA explains that its proposal will "ensure that when fugitive emissions are found from the pipe itself that necessary repairs are completed accordingly." Id. EPA's proposal is vague and fails to provide an adequate opportunity to formulate meaningful comments because EPA does not explain how leak detection should be accomplished for "yard piping" as compared to other already-listed fugitive emissions components, where there are identifiable leak points (such as valve stems or flange interfaces) that are the target of monitoring. For example Section 8.3 of Method 21 (which applies to LDAR standards such as the one here that specify a concentration-based leak definition) explains that monitoring should be conducted "at the surface of the component interface where leakage could occur." Section 8.3 also includes detailed instructions for individual components (such as valves), where particular leak points are identified. In contract, there is no identifiable leak point for "yard piping" that reasonably would be the target of monitoring. In fact, using Method 21, there is no obvious way that the required monitoring could be conducted because of the expansive lengths of pipe where the sort of leaks that EPA seems to be concerned about might occur. Before finalizing a requirement to include yard piping in the definition of fugitive leak component, EPA must provide additional explanation of how the LDAR provisions would apply and provide an opportunity for public comment on that necessarily more specific proposal.

NSPS OOOO and OOOOa requirements. For that time period, a site could have storage vessels subject to NSPS OOOO or OOOOa and be subject to NSPS OOOOb fugitive monitoring. See Comment 12.5 regarding the proposed reconciliation of NSPS OOOO and OOOOa with NSPS OOOOb and EG OOOOc.

- **Existing clarifying language from NSPS OOOOa should be retained.** Since NSPS OOOOb proposes to allow natural gas-driven pneumatic controllers and pumps in limited circumstances (e.g., sites in Alaska without access to electric power), the existing language from the NSPS OOOOa definition should be retained to clarify what is considered fugitive emissions.

Based on the above clarifications, API offers the following suggested redline, which retains much of the current NSPS OOOOa definition, to the proposed definition of fugitive emissions component in NSPS OOOOb and EG OOOOc:

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411, §60.5411a, or §60.5411b, thief hatches or other openings on a controlled storage vessel not subject to §60.5395, §60.5395a, or §60.5395b, compressors, instruments, and meters~~, and in yard piping~~. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

2.3 Delay of repair requirements should be expanded.

Due to the hundreds of thousands of sites that would be subject to fugitive monitoring under NSPS OOOOb and EG OOOOc, EPA should expand the proposed delay of repair requirements in the following ways:

- **Consistent with the requirements for natural gas processing plants, EPA should allow for delay of repair due to parts unavailability.** NSPS VVa, incorporated by reference in NSPS OOOO and OOOOa for gas plants, allows for delay of repair beyond a unit shutdown if "*valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.*"[17] In the Preamble to the November 2021 Proposal[18], EPA recognized that operators of older equipment may experience delays in obtaining replacement parts. Given current supply chain issues and the larger number of well sites, centralized production facilities, and compressor stations, EPA should expand the current delay of repair requirements to include delays because of parts unavailability.
- **EPA should add other potential circumstances beyond an operator's control that would require a delay of repair.** Repairs may be delayed due to circumstances not currently listed in the rule. Specifically, there are seasonal constraints related to farming and/or endangered species where operators cannot bring a rig in or have surface disturbance. Delay of repair should be allowed for these unique situations.

Based on these items, API offers the following suggested redlines to §60.5397b(h)(3), which are based on existing regulatory language from NSPS VVa:

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[17] 40 CFR §60.482-9a(e)

[18] 86 FR 63174

(3) Delay of repair will be allowed:

(i) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel~~.~~*;*

(ii) If the necessary replacement part supplies have depleted and supplies had been sufficiently stocked before supplies were depleted, the repair must be completed as soon practicable, but no later than 30 days once the necessary replacement part supplies are available; or

(iii) If the necessary repair equipment cannot be brought to the site for reasons, such as lease restrictions for farming or seasons for endangered species, the repair must be completed as soon practicable, but no later than 30 days once repair equipment may be brought to the site.

2.4 Repair timelines should be consistent for leaks identified using AVO or OGI.

The repair timelines should be the same whether the fugitive emissions at well sites, centralized production facilities, and compressor stations are identified using AVO, OGI, or Method 21 because the necessary repair actions are agnostic to the detection method. In other words, operators should have the same time to make repairs regardless of leak detection method because the repair actions depend more on the leaking component rather than detection method.

EPA's stated reason for requiring shorter repair timelines is *"so that the monthly AVO inspections do not overlap the repair schedule"*[19]. This justification is insufficient for two reasons:

- As proposed, monthly AVO inspections would apply only to compressor stations. This overlap would not occur for bimonthly or quarterly AVO inspections at well sites and centralized production facilities.
- EPA has allowed repair timelines to overlap with inspection in other regulations. Under existing LDAR regulations, a component may be on delay of repair for multiple monitoring periods in certain circumstances.

While AVO is generally more effective at detecting larger emissions, the existing OGI repair timelines do not consider emission rate because OGI cannot quantify the leak rate. The same inability to quantify fugitive emissions also applies to AVO, and so EPA should have the same repair timelines for both detection methods. Finally, consistent timelines would also streamline compliance.

To address this concern, API offers the following suggested redline of §60.5397b(h):

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[19] 87 FR 74737

Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made ~~in accordance with paragraphs (h)(1)(i) and (ii) of this section.~~

~~(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using visual, audible, or olfactory inspection.~~

~~(ii) If you are complying with paragraph (g)(1)(i) through (iv) of this section, a first attempt at repair shall be made~~ no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than ~~15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and~~ 30 calendar days after the first attempt at repair ~~as required in paragraph (h)(1)(ii) of this section.~~

2.5 EPA should clarify depressurized equipment are exempt from fugitive emissions monitoring.

State rules, including New Mexico[20] and Colorado[21], exempt depressurized equipment[22] from fugitive emissions monitoring because leak surveys are not anticipated to result in emissions reductions at these facilities. Monitoring would resume once the site or equipment is back in service. EPA should provide a clear exclusion for these types of facilities or equipment under both NSPS OOOOb and EG OOOOc. One suggestion would be to model the regulatory language on the existing storage vessel out of service and return service requirements.

See also Comment 13.3.

2.6 Additional clarification is needed for the proposed definition of modification for a centralized production facility.

EPA's proposed definition of modification for the collection of fugitive emissions components at a centralized production facility presents a challenge since the operator of a centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility especially when the operator differs between the centralized production facility and the offsite wells that send production to it. The operator of the centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility since the upstream operator is typically only required to notify the centralized production facility operator when a new well is drilled and starts to send production to the gathering system. The upstream operator may not necessarily identify the specific centralized production facility. EPA may not have anticipated this scenario in proposing the definition of modification for the collection of fugitive emissions components at a centralized production facility.

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[20] 20.2.50.116.C(9) NMAC

[21] https://drive.google.com/file/d/1a3IJ74txUxJ241wgh-ZMRx0Rn7LV3z2V/view

[22] The CO regulations reference depressurized equipment, while the NM regulation references temporarily abandoned wells.

To address this concern, API suggests that the modification criteria for centralized production facilities be limited to "An increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility". This criterion is simple, clear, and aligned with the purpose and definition of a centralized production facility, which is to gather hydrocarbon liquid production into storage vessels. As such, API offers the following suggested redline of §60.5365b(i)(2):

> *For purposes of §60.5397b and §60.5398b, a "modification" to centralized production facility occurs when~~:~~ an increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility.*
>
> ~~*(i) Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;*~~
>
> ~~*(ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or*~~
>
> ~~*(iii) A well site subject to the requirements of §60.5397b or §60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.*~~

We also suggest EPA add clarification to the definition for central production facility that addresses custody transfer.

2.7 EPA's proposed well closure plan requirements present several technical and legal issues.

After reviewing EPA's proposed well closure plan requirements, API has identified the following technical and legal issues:

- **The proposed well closure plan requirements are duplicative with other regulations.** Well closure requirements are within the jurisdiction of State Oil & Gas Commissions and other agencies, not the EPA. Under state law, a well is required to be plugged and abandoned when it has reached the end of its useful life. In all States, operators must provide written notice of plugging and comply with regulatory requirements to plug and abandon the well, including removing equipment, setting downhole plugs, cementing in the casing, capping the well to prevent fluid migration and restoring the surface site. These practices are done to permanently confine oil, gas and water into the strata in which they were originally found. For wells located on federal lands, separate BLM requirements also apply for well closure. Depending on the well location (e.g., located in an area with potash mining), additional requirements may also apply. For some wells, EPA would be adding a fourth set of well closure requirements.

  Therefore, EPA's proposed notifications and well closure plan requirements are duplicative, unnecessary, and increase administrative burden while providing no discernible accompanying environmental benefit when an operator is working to properly close a well. In certain cases when an emergency plugging is required, the proposed notification timelines may be impossible to meet.

- **EPA does not have the technical expertise to review well closure plans.** State Oil & Gas Commissions have the technical knowledge to evaluate well closure plans, because they have the jurisdiction for well closure. Without the technical knowledge, EPA's proposed well closure plan requirements require

significant operator and agency resources but provide no additional environmental benefit. Operators should only be required to maintain records of an approved well closure plan by the state authority with jurisdiction; these records could be provided to EPA upon request.

Under existing State and BLM requirements, well closure plans include detailed information on the well casing, tubing, and rod dimensions, perforation depths, proposed plug materials, depths, tagging, and verification, leak testing for cast iron bridge plug (CIBP), and other required data.

- **EPA does not have authority under CAA § 111 to impose financial assurance requirements.** Part of the proposed well closure plan is a "description of the financial requirements and disclosure of financial assurance to complete closure". This requirement is clearly beyond EPA's authority under the Clean Air Act (CAA). For more details, refer to Comment 12.8.

- **The proposed requirements may create unforeseen liability consequences.** EPA has not clarified how the proposed well closure requirements will transfer with ownership. Under State and BLM rules, chain of title is defined. EPA should not create duplicative requirements that could create potential liability consequences for operators.

- **The notification prior to well closure should be removed. If EPA finalizes the proposed well closure requirements, EPA must clarify when a well closure plan is required to be submitted.** Language at §60.5397b(l) potentially conflicts with §60.5420b(a)(4) in terms of whether a well closure plan needs to be submitted every time that production ceases for more 30 days or only when the operator intends to close the well and stop fugitive emission monitoring. "Cessation of production" is not defined in the proposed regulations. A 30-day period from cessation of production is not indicative of well closure. Operators may have many instances where wells are shut-in for periods of 30 days or more, with complete intent to return the wells to production. A few examples include a facility undergoing maintenance or repair, shut-in for offset fracturing, lack of access to gathering, or wells on cycled production. We request EPA clarify that the well closure plan requirements and notification only when operators intend to permanently close the well and stop fugitive monitoring.

Overall, API recommends that requirements within NSPS OOOOb and EG OOOOc pertaining to well closure be limited to the following:

- **A recordkeeping requirement to maintain records of an approved well closure plan by the local authority with jurisdiction.** This recordkeeping only requirement would avoid unnecessary and duplicative requirements with State Oil and Gas Commissions. The records could be submitted to EPA upon request.

- **A final OGI survey to confirm no detected fugitive emissions after well closure.** EPA could still require a final OGI survey after well closure.

3.0 Alternative Leak Detection Technologies including Periodic Screening and Continuous Monitoring

API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA

to make key adjustments in the final rules to enhance the use of these technologies and to not unintentionally disincentivize development and deployment of these technologies. Making alternative technologies more accessible in these rules can also have synergistic benefits with measurement-informed inventory goals in related rulemaking such as the Inflation Reduction Act's Methane Emissions Reduction Program and EPA's Greenhouse Gas Reporting Program.

These adjustments are described in our comments below, including initial comments on EPA's FEAST modeling. While API is exploring additional modeling analyses, due to the short comment period, any additional modeling analysis may be provided in a subsequent submittal. We welcome the opportunity for future discussions on this important topic with EPA staff.

3.1 Comments Regarding Both Periodic Screening and Continuous Monitoring Technologies

3.1.1 Technologies should be available for use upon finalization of NSPS OOOOb and EG OOOOc.

To facilitate adoption of alternative leak detection technologies, operators need options available beginning with finalization of the proposed rules. EPA's proposed 270-day review timeline means that technologies would likely not be approved until after the first AVO, OGI, or Method 21 inspection, since the initial inspection would be required 90 days after NSPS OOOOb is finalized. This gap may disincentive the use of alternative technologies as operators would already be required to implement the standard fugitive emissions monitoring program with AVO, OGI, and/or Method 21 inspections.

Recognizing that EPA is unable to approve technologies until the rules are finalized, API proposes that alternative technology applications be granted conditional approval if they are submitted within 90 days after the final rule is published in the Federal Register (based on the proposed timelines for the initial AVO, OGI, or Method 21 surveys). This initial conditional approval period would allow for the immediate use of those alternative technologies to achieve initial compliance with NSPS OOOOb. An alternative to initial conditional approval could be extending the deadline for initial monitoring surveys from 90 day to one (1) year in §60.5397b(f) and §60.5398b(b)(2). Time beyond the 270-day conditional approval would be needed for operators to contract with vendors and conduct the initial surveys.

Operators would be able to use the conditionally approved technologies until EPA provides written disapproval to the requestor. Disapproval of a conditionally approved technology should not be considered a deviation for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology. EPA has already proposed the idea of conditional approval for alternative technologies, so this idea could be extended to allow for technologies to be available for initial compliance. EPA could also utilize technologies approved by a state or another country (e.g., Colorado or Canada) as a starting point for initial conditional approval.

In place of or in addition to initial conditional approval, API recommends that EPA prioritize review of initial alternative technology applications (submitted within 90 days after final rule is published in Federal Register) based on the following criteria:

- The technology is already approved for use by a state or another country. Approval by another agency means that the technology has been reviewed previously and is likely to meet EPA's proposed minimum detection threshold of ≤ 30 kg/hr (based on a probability of detection of 90%) as shown in Table 1 and Table 2 to NSPS OOOOb.
- The technology is already used by one or more operators for monitoring under voluntary efforts or regulatory programs. One potential measure could be the number of sites monitored in 2022 using the alternative technology under voluntary efforts or other regulatory programs.

An initial conditional approval period and prioritization of review would allow for quicker adoption of alternative technologies and would also alleviate pressure from EPA to review a potential influx of applications upon rule finalization. Without these measures, EPA could be overwhelmed with applications, and the full 270-day review period would pass before the first technologies would be conditionally approved.

3.1.2 EPA should clarify how the review and conditional approval process will be implemented.

We request EPA provide the following clarifications regarding the application review and conditional approval process for use of alternate technologies:

- EPA should clarify that operators are able to use conditionally approved technologies until EPA provides written disapproval to the applicant.
- EPA needs to consider how to effectively notify operators when a conditionally approved technology is disapproved.
- EPA should also clarify that disapproval of a conditionally approved technology should not affect compliance for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology.

EPA should also elaborate on how deficiencies in an application will affect the proposed review timelines. For the initial 90-day review and final 270-day review, the proposed regulatory language implies that deficiencies in an application will result in disapproval and require the applicant to revise its request and restart this process. As with other application processes, agencies will typically issue requests for additional information with appropriate deadlines so that applicants can resolve deficiencies without restarting the entire application process. Forcing applicants to restart the process for any application deficiency would further delay the approval of alternative technologies for use by operators.

3.1.3 Emissions detected from covers and closed vents systems using alternative technology or while doing required follow-up surveys do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

As discussed in more detail in Comment 5.1 , emissions detected from covers and closed vent systems are not necessarily violations of the "no identifiable emissions" standard since it is a work practice standard rather than a numerical zero emission standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through alternative technology or a required follow-up survey triggers the

obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented. Treating emissions detected from covers and closed vent systems as violations not only fails to acknowledge technical reality contrary to best system of emission reduction (BSER), but it also disincentivizes the use of alternative technology.

3.1.4 While API appreciates EPA providing modeling, EPA's current model overestimates the effectiveness of AVO and OGI.

We appreciate EPA's efforts to create a technology-agnostic, performance-based alternative test method framework supported by an underlying, publicly available FEAST model. In EPA's model, the probability of detection curves for AVO and OGI have 100% probability of detection for leaks above approximately 200 g/hr and 60 g/hr, respectively. While these are useful detection methods in various applications, these characterizations overestimate their effectiveness in certain field conditions and leads to impractical performance standards for the alternative technologies as discussed further in Comment 3.3.1 for periodic screening and Comment 3.4.5 for continuous monitoring.

For example, AVO inspections are less likely to find large leaks if they are located above the person performing the inspection, they occur in areas that the person cannot enter due to safety concerns (e.g., potential for H_2S exposure), or they are located in areas with high noise among other reasons. While 60 g/hr is the current NSPS OOOOa and proposed NSPS OOOOb and EG OOOOc standard for OGI cameras, probability of detection for OGI also depends on the camera operator and field conditions.[23] A more realistic characterization of AVO and OGI detection methods would create a more realistic equivalency model for alternative technologies. Due to the short comment period, we may continue to analyze EPA's assumptions about intermittency of leaks, model plant configurations (i.e., equipment types and component counts), and leak occurrence in subsequent comments.

3.1.5 The alternative technology framework should allow flexibility in conducting leak surveys due to seasonal challenges.

The alternative technology framework should allow for flexibility in conducting AVO/OGI and screening surveys due to seasonal challenges and weather events. Some examples include but are not limited to:

- Snow cover can adversely affect the ability of some alternative technologies to detect methane during part of the year.
- High winds can also prevent aerial-based technologies from being deployed on certain days.
- Weather events such as hurricanes may limit the ability to deploy OGI camera operators to sites for surveys.

The alternative technology framework should allow different technologies to be deployed at appropriate frequencies throughout the year. The deadline for the next survey would be based on the type of site and the last survey conducted. As an example, at single wellhead only site, an operator could conduct AVO inspections for the first two quarters of the year followed by a screening survey at ≤ 2 kg/hr and then another AVO inspection no later than four months after the screening survey, based on EPA's proposed requirements. Flexibility in applying alternate screening technologies should include provisions that use of a different technology than originally

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[23] Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. *Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions*. Environmental Science & Technology 2020 54 (18), 11506-11514 DOI: 10.1021/acs.est.0c01285

planned (due to weather or other external factors) constitutes an allowance, not a deviation from an operator's monitoring plan.

3.1.6 Framework for alternative leak detection technologies should allow multiple technologies, including satellite, to be combined. More combinations of technologies should be added to the proposed periodic screening matrices.

Overall, API believes that allowing the use of a combination of alternative leak detection technologies can be effective to find and fix leaks. This alternative approach recognizes that each leak detection technology (AVO, OGI, Method 21, periodic screening, or continuous monitoring) has strengths and weaknesses in terms of detection threshold, proximity to the source, localization performance, deployment frequency, and costs. For example, ground-based OGI has a low detection threshold and localizes the leak to a particular component but requires proximity to the source and is infeasible to deploy at higher frequencies. Whereas satellites, aerial and continuous technologies can be deployed more frequently than ground-based OGI, the increased distance from the source may not detect leaks on the component level. With these remote detection technologies, resources can be deployed more efficiently to repair leaks – operators would only need to visit sites with detected emissions to make repairs whereas using only OGI surveys require operators to visit each site but could result in no detected emissions. A continuous monitoring system can quickly detect a leak and depending on sensor location, provide an approximate location, but may not fully visualize its location like a plume map from a satellite or aerial survey. In other words, no individual leak detection technology offers a perfect solution.

By allowing the option for a combination of these various technologies into a single monitoring plan or framework, the weaknesses of one technology can be offset by the strengths of another, and the selected technologies work together to improve leak detection and reduce emissions in a flexible and cost-effective manner. Technologies can be combined such that larger emissions are quickly detected, and technologies that detect smaller emissions are deployed less frequently. Finding and fixing the biggest leaks quickly can greatly impact the overall emission reductions.

A multi-layered approach for leak detection combines various technologies to achieve greater emission reductions. Some fugitive emissions may be detected with traditional OGI or AVO during regular LDAR inspections. Intermittent emissions are not always detected during OGI or AVO inspections; however, they may be detected by a continuous monitoring system. Deploying continuous monitors is not an option for all sites, such as those without access to reliable grid power. Alternatively, an aerial survey may detect emissions from such sites over a large area. Although satellites cannot always detect emissions at the component level, they can be useful for basin-wide detection of large emissions that may occur outside of scheduled inspections. This concept of layering various leak detection technologies is illustrated in the graphic below where lines and layers represent strengths of a given technology while the dashed circles represent weaknesses allowing undetected emissions. An example of this multi-layered approach using data from the Permian Basin can be found in an industry pre-publication paper[24].

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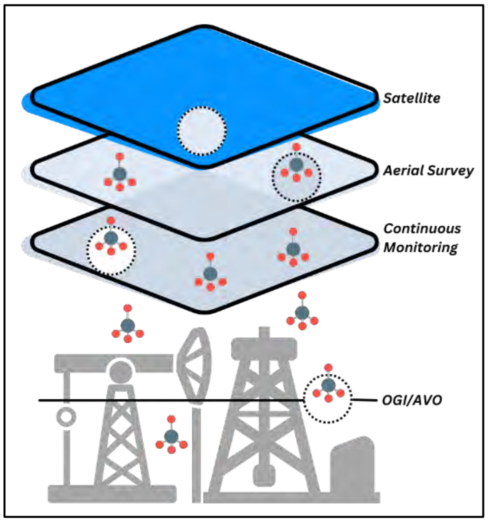
[24] Cardoso-Saldaña FJ. *Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities*. ChemRxiv. Cambridge: Cambridge Open Engage; 2022; This content is a preprint and has not been peer-reviewed. DOI: 10.26434/chemrxiv-2022-f7dfv

Figure 1. Multi-layered Approach for Leak Detection



EPA has already included the idea of layering technologies with the screening survey plus annual OGI survey options in the periodic screening matrices. API has two specific suggestions regarding an alternative multi-layered approach for leak detection:

- **API recommends that continuous monitoring (see also Comment 3.4.1) and satellite technology be included as options directly in the matrices in combination with the periodic survey with and without annual OGI.** In other words, combinations like "Quarterly + Weekly Satellite + Annual OGI", "Quarterly + Weekly Satellite", "Quarterly + Continuous + Annual OGI", and "Quarterly + Continuous" should be modeled and added to the periodic screening matrices with appropriate detection thresholds for the screening technology. Satellite technology would be defined with a ≤ 100 kg/hr detection threshold and a weekly frequency. Having frequent satellite surveys will allow reducing the number of periodic surveys per year for a given detection threshold with and without an annual OGI survey.

- **Separately, we would also welcome an additional optional and flexible framework independent from the periodic screening matrices and case-by-case AMEL process where an operator can develop a monitoring plan for each basin/site with their chosen suite of EPA-approved technologies via EPA-approved modeling.** Similar to EPA's proposed clearinghouse approach to approving alternative screening technologies, EPA could evaluate and approve different modeling platforms for use in developing monitoring plans. Modeling could be refined over time based on data generated through the monitoring plan. The initial modeling should represent the highest emissions level since emissions should decrease over time as NSPS OOOOb and EG OOOOc are implemented over the next several years. This approach would both allow the technology to mature over time and a streamlined approach to alternative modeling compared to the existing case-by-case AMEL process.

  This flexible framework gives operators a clear pathway for a custom, fit-for-purpose option and would be an alternative to both the AVO/OGI requirements and alternative technology requirements. To benefit smaller operators, EPA should consider both a conservative, and realistic, default plan that allows for flexibility in monitoring technology as well as an option where an approved monitoring plan can be used by other operators with similar assets.

3.1.7 Repair timelines should be consistent for leaks using AVO/OGI or alternative leak detection technologies.

Recognizing that repair timelines are part of the overall effectiveness of a leak detection program, API recommends that repair timelines be consistent between traditional (AVO, OGI, or Method 21) and alternative (periodic screening or continuous) leak detection programs. Repair actions depend more on the leaking component rather than detection method. The proposed repair or corrective action timelines in §60.5398b(b)(4) for periodic screening and §60.5398b(c)(6) for continuous monitoring are shorter than those in §60.5397b(h) for fugitive emissions components and §60.5416b(b)(4) for covers and closed vent systems. The shorter repair timelines for alternative leak detection technologies may disincentivize their use. Consistent repair or corrective action timelines would streamline compliance and facilitate the use of multiple technologies. If EPA chooses to finalize shorter repair timelines for alternative technology, API recommends that repairs be prioritized based on higher detected emissions.

3.1.8 EPA should allow operators to use alternative technology to comply with NSPS OOOOa without an AMEL.

Since the proposed NSPS OOOOb fugitive monitoring requirements including alternative technology are at least as stringent as the existing NSPS OOOOa requirements, EPA should allow operators use of alternative technology for NSPS OOOOa compliance without going through the Alternative Means of Emission Limitations (AMEL) process or waiting for state plans to be fully implemented under EG OOOOc. Both the AMEL process and EG OOOOc state plan implementation could take years. EPA can make the NSPS OOOOb alternative technology a compliance alternative for NSPS OOOOa since EPA is planning to update certain aspects of NSPS OOOOa in conjunction with this rulemaking. This addition should not require further notice since the requirements are at least as stringent as the existing NSPS OOOOa requirements. Some alternative technology (e.g., aerial surveys) is deployed over a particular basin or portion thereof and could include both NSPS OOOOa and OOOOb sites. Therefore, allowing the use of alternative technologies for NSPS OOOOa compliance without an AMEL would further incentivize the adoption of these emerging technologies.

3.2 The term “investigative analysis” should replace “root cause analysis”.

The specific term “root cause analysis” has other meanings and specific denotations in various regulations and in the oil and gas industry. There is also a legal issue with how this term can be interpreted in any legal or enforcement proceedings, as well as how it could obligate operators to actions or additional requirements that are not necessarily included within this proposed rule.

API understands and supports EPA’s intent for investigating why certain emission events or leaks have occurred, but recommends the removal of the term “root cause analysis” and replacement with the term “investigative analysis” within NSPS OOOOb and EG OOOOc.

We offer additional comments specific to how “root cause analysis” has been proposed with respect to the super-emitter response program in Comment 1.1.6.

3.3 Comments Specific to Periodic Screening Technology

3.3.1 Proposed periodic screening matrices do not incentivize the use of the alternative technology.

While API acknowledges EPA's proposed matrices of minimum detection thresholds and frequencies, they do not incentivize the use of alternative technology as proposed. To have the same monitoring frequency as OGI, alternative technology must have a minimum detection threshold of ≤ 1 kg/hr for both quarterly OGI and semiannual OGI requirements. This proposed performance level effectively limits the alternative technology options as operators are more likely to use technology with the same or less frequent monitoring than OGI. The proposed performance standards in the matrices are more stringent than needed in part because EPA's FEAST model overestimates the effectiveness of AVO and OGI inspections as mentioned previously in Comment 3.1.4. To incentivize the use of alternative technologies, API believes that quarterly screening surveys with an annual OGI survey should equate to a minimum detection threshold of ≤ 10 kg/hr for sites subject to quarterly OGI; the rest of the matrices would be adjusted accordingly. Supporting modeling analysis may be provided in subsequent comments.

These matrices also do not appear to be based primarily on the minimum leak detection threshold. In proposed Table 1 to Subpart OOOOb of Part 60, the minimum detection threshold is proportional to screening frequency between monthly and bimonthly frequencies without annual OGI (i.e., minimum detection threshold is halved for twice as frequent monitoring). However, if an annual OGI survey is included with monthly and bimonthly screening surveys, the minimum detection threshold is decreased by a factor of 3 instead of the expected 2 (i.e., monthly + annual OGI requires 30 kg/hr detection while bimonthly + annual OGI requires 10 kg/hr instead of the expected 20 kg/hr). While frequency and detection threshold are not the only parts of a leak detection program, one would expect frequency and detection thresholds to be roughly proportional assuming that other aspects of the leak detection program (e.g., repair timelines) are constant.

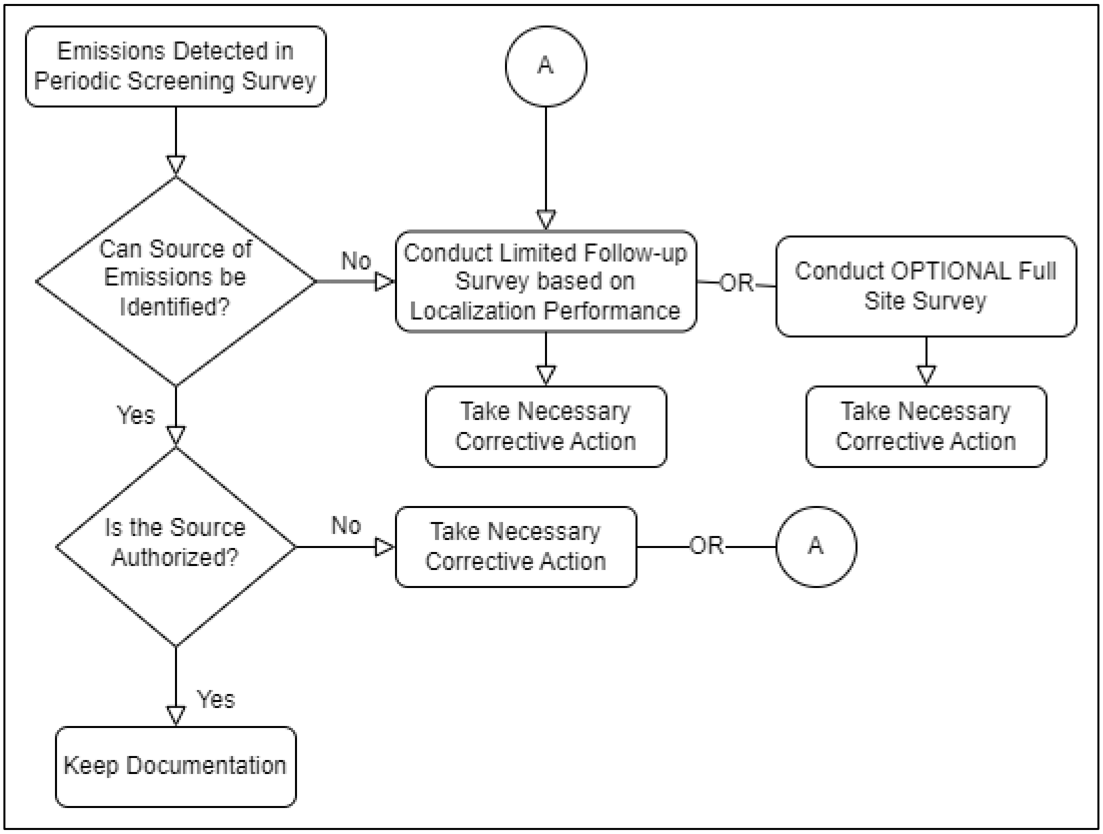
3.3.2 Proposed follow-up actions for periodic screening surveys should be revised.

As discussed in Comment 3.1.7, proposed repair or corrective action requirements for alternative technology should not disincentivize their use. API supports that a full site follow-up OGI survey fulfills the annual OGI survey requirement (where applicable) as indicated in §60.5398b(b)(3)(iii). Regarding the proposed requirements for periodic screening in §60.5398b(b)(4), API offers the following suggestions:

- **The requirements on receiving results of periodic screening and conducting follow-up surveys should be separated from other repair requirements to avoid confusion.** The language in §60.5398b(b)(4) implies that receiving periodic screening results and conducting follow-up surveys are repair requirements when they are both monitoring requirements to detect or confirm leaks.
- **The timeline for receiving results of periodic screening should be extended from 5 calendar days to 5 business days.** Periodic screening surveys can cover hundreds of sites, and so vendors and operators need additional time to process the data for further action.
- **Follow-up surveys and inspections should be limited to sites where the source of emissions cannot be identified based on the localization performance of periodic screening results and other operational information.** Follow-up OGI surveys and cover and closed vent system inspections should not be required if the source of detected emissions can be identified based on the localization performance of the

alternative technology and/or other data. Alternative technology has varying degrees of localization performance in terms of being able to identify emissions on the site-level, equipment group-level, equipment-level, or component-level. Our proposed follow-up action process gives operators the necessary flexibility in responding to detected emissions and is presented in Figure 2and described in detail below.

Figure 2. Flowchart of Proposed Follow-up Actions for Periodic Screening Surveys



When emissions are detected in a periodic screening survey, the operator first tries to identify the source of emissions from the survey results and other available information. For safety and cost reasons, follow-up surveys in the field should be limited to situations where additional information is needed to identify or confirm the source of detected emissions. If the source of detected emissions can be identified, next steps would be based on the type of source.

- If the source of emissions is permitted or otherwise authorized, including maintenance activities, no further action would be required other than to keep documentation. Examples include, but are not limited to, engine or turbine exhaust, uncontrolled storage vessel, planned compressor blowdown, planned engine or turbine startup or shutdown, or properly operating control device. This situation is especially important to compressor stations where periodic surveys are likely to detect emissions from sources operating in compliance with applicable requirements.
- If the source of emissions is a process upset, leak, or other unauthorized release, the operator should be able to directly take necessary corrective actions rather than spending time and effort on a follow-up survey to confirm the source. Taking direct action with the appropriate timelines reduces emissions faster than conducting a follow-up survey first. If the operator determines that a follow-up survey is appropriate to confirm the source of detected emissions, they should be

able to conduct one based on the localization performance of the technology or an optional full site survey.

If the source of detected emissions cannot be identified, operators would conduct a follow-up survey limited to the localization performance of the alternative technology or conduct a full site survey to satisfy the annual OGI survey requirement (if applicable). If two or more full site surveys are conducted within a 12-month period, the most recent full site survey would determine the deadline for the next required annual OGI survey (if applicable). As an example, an alternative technology that can only detect leaks on the site level would require a full site survey while one that can detect leaks down to the equipment would require follow-up surveys only on equipment with detected leaks. Requiring a full site survey anytime that emissions are detected from periodic screening surveys is practically the same monitoring requirement as the primary AVO/OGI requirements but with the additional cost of conducting periodic screening surveys. Due to the large volume of data that can be generated from periodic screening surveys, limited follow-up surveys allow OGI resources to be used in a focused and cost-effective manner. Limited follow-up surveys could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to a full follow-up survey required for every time emissions are detected during a periodic screening survey.

- **Repair timelines should be consistent with AVO/OGI requirements.** Repair timelines should be consistent between traditional and alternative leak detection programs to streamline compliance and facilitate the use of multiple technologies. Therefore, the language in §60.5398b(b)(4)(iii) should simply reference the appropriate repair requirements for fugitive emissions components and covers and closed vent systems.
- **The proposed investigative analysis for control devices in §60.5398b(b)(4)(iv) and covers and closed vent systems in §60.5398b(b)(5) should be initiated within 5 business days.** While API recognizes the importance of proper control device and cover and closed vent system operation, we propose that the investigative analysis be initiated within 5 business days of either receiving the periodic screening survey results in the case that the control device, cover, or closed vent system can be identified as the source of emissions or conducting the limited or full site follow-up survey, whichever is later. This proposed timeline would be consistent with the framework we propose for the SERP in Comment 1.1. EPA's proposed 24-hour timeline is too short to be practical.
- **The proposed investigative analysis for covers and closed vent systems in §60.5398b(b)(5) is more stringent than the repair requirements under §60.5416b(b)(4) and should be removed.** As proposed in §60.5398b(b)(5), a leak or defect in a cover or closed vent system detected by follow-up inspections would require additional analysis beyond repair, including a determination of whether it was operated outside of its design. A leak or defect in a cover or closed vent system detected by routine inspections would be subject only to repair under §60.5416b(b)(4). The investigative analysis for covers and closed vent systems under the alternative technology requirements goes beyond the primary standards, and so §60.5398b(b)(5) should be removed.
- "**Root cause analysis" should be replaced with "investigative analysis".** Consistent with Comment 3.2, the term "investigative analysis" should replace "root cause analysis" in §60.5398b(b)(4)(iv) and §60.5398b(b)(5) (if that requirement remains).

3.4 Comments Specific to Continuous Monitoring Technology

We support EPA's inclusion of continuous monitoring in §60.5398b(c), and our members believe there is great potential in the use of continuous / near-continuous methane monitoring technologies. However, some of the proposed elements are problematic for practical implementation and use of continuous monitors. Therefore, we offer the following comments to craft a more functional continuous monitoring program based on the types of monitors that currently exist, focused on the desired outcome of detecting methane emissions at oil and natural gas production facilities to identify necessary response or repairs, if warranted.

3.4.1 The use of continuous monitoring technology within the periodic screening matrices must be clarified.

The proposed rule language is unclear whether continuous monitoring technology could also be used under the periodic screening survey requirements in §60.5398b(b) and associated matrices. For continuous monitoring technology that simply detects rather than quantifies methane emissions, these technologies could be used for periodic screening surveys. In these situations, the continuous monitor acts like a smoke alarm to notify operators of potential issues. Since continuous monitors can be used more frequently than monthly, EPA should consider adding a more frequent tier or a separate continuous monitoring row to the matrices. The equivalent emission reductions from continuous monitoring could be demonstrated through appropriate modeling. **We recommend incorporating continuous monitoring into the alternative screening matrix for the reasons discussed and to streamline inclusion into the monitoring plan framework we have described in Comment 3.1.6.**

3.4.2 The framework for continuous monitoring should be designed with both fenceline and within-the-fenceline technologies in mind.

As written, EPA's proposed requirements for continuous monitoring appear to be designed for fenceline technology. EPA should clarify that both fenceline and within-the-fenceline technologies can be used and provide details on how implementation would differ between them. API fully expects continuous monitoring technology for methane detection to come within the fenceline and get closer and closer to the source, unlocking emissions reduction potential that is unlikely to be realized by sensors installed on the perimeter. These within-the fenceline technologies will not have many of the limitations of today's fenceline solutions – including no need for wind or meteorological data because these sensors will be in closer proximity to equipment. Limiting the continuous monitoring requirements in this rulemaking to fenceline only would potentially reduce incentives to develop more advanced technology.

3.4.3 Currently available continuous / near-continuous monitoring technology detect methane emissions. The requirement for quantification should be amended.

Current continuous or near-continuous monitors are used to detect emissions and allow for a real-time response by operators; however, these monitors are not and should not be treated as a continuous emission monitoring system like a more traditional "CEMS". These monitors are "high frequency" monitors and not necessarily "continuous" in a traditional sense. The main focus of the monitors should be in the detection of emissions similar to the current OGI framework where the technology is used to find a leak and an operator can then respond, and if appropriate, to fix the leak.

The proposed framework should not be limited by a technology's ability to quantify emissions as this severely limits the types of monitors that can be used and offers a disincentive for operators to deploy the high frequency monitors currently available for deployment. Many technologies on the market today purport to quantify, but industry experience is that the value and accuracy is driven by the system's ability to act as a smoke alarm, where a certain threshold triggers a response system that notifies operators. There is no continuous monitoring technology today that actually "measures" a rate. The "quantification" capability is not derived from the underlying "smoke alarm" sensor but layering that sensor with wind, meteorological and other plume model / inversion model information / assumptions, which has untenable uncertainty.

Therefore, we believe these types of monitors should be considered as effective as the BSER standard, which is quarterly OGI for many larger well sites, central production facilities, and compressor stations. This proposal would have the technologies follow an approach similar to the matrix for other alternate technologies provided in §60.5398b(b) and Tables 1 and 2 to Subpart OOOOb and not follow the action levels in §60.5398b(c).

3.4.4 Continuous / near-continuous monitors should be evaluated against BSER, which is quarterly OGI.

As mentioned, currently available monitors allow for an alarm and response framework that allows operators the ability to evaluate the alarm and mitigate potential leaks. Due to this, continuous monitoring should be compared against the effectiveness of the technology in allowing response and potential repair of leaks against the BSER requirement of quarterly OGI and not based on the type of "fenceline" type framework that has been proposed. Per §60.5398b(c)(1), EPA has defined continuous monitoring as **"***the ability of a measurement system to determine and record a valid methane mass emissions rate of affected facilities at least once for every twelve-hour block."* This equates to daily scans at the facility, which sets an unrealistically high bar for implementation when compared against BSER that sets the most stringent monitoring at quarterly OGI and monthly AVO. The use of high frequency monitors should be consistent with BSER based on the detection capabilities of the monitors.

3.4.5 If EPA keeps its proposed framework for continuous monitoring, the proposed action levels should be revised.

While API overall recommends that continuous monitoring be incorporated with periodic screening to create a single framework for alternative technology, we have concerns with the proposed action levels if EPA choose to keep its proposed separate framework for continuous monitoring. The proposed action levels are based on EPA's FEAST modeling, which does not accurately characterize the effectiveness of AVO and OGI as discussed in Comment 3.1.4. We see merit in including a framework for future technologies that could detect and more accurately quantify emissions, but the currently proposed thresholds are not reflective of actual operations.

Regarding the proposed action levels in §60.5398b(c)(4), API offers the following suggestions:

- **Action levels should be based on detected emissions above an established baseline.** As proposed, the action levels appear to be based on total site emissions, which includes routine or baseline emissions, rather than emissions above an established baseline. Under continuous monitoring, fugitive emissions from leaks are additive to baseline emissions, but they are not additive under AVO/OGI/Method 21 and periodic screening programs. Action levels based on total site emissions effectively sets a limit on site emissions without considering the size or number of emission sources at a site, which could disincentivize the use of continuous monitoring, especially at larger sites. Also, failure to consider baseline emissions

would not exclude contributions from other nearby sources of methane emissions including but not limited to other sites, farming activities, graywater trucks, human populations, etc. EPA should revise the action levels to be based on emissions above baseline and propose how operators establish those baseline emissions.

- **The rolling 90-day (long-term) action levels should be removed as they have no equivalent in the AVO/OGI/Method 21 or periodic screening requirements.** Both the AVO/OGI/Method 21 and periodic screening programs require action to address emissions detected during the monitoring; in other words, emissions are compared to an established immediate or short-term threshold. Neither program has a long-term emissions threshold for action like the rolling 90-day action levels proposed for continuous monitoring. A long-term action level is at best a lagging indicator of an event and would make the investigative analysis of an exceedance more challenging. EPA has not clarified how operators should treat exceedances of the short-term action level that could also cause an exceedance of the long-term action level; operators resolve the short-term event in a timely fashion but may still exceed the long-term action level without any additional events or leaks. Based on these various reasons, EPA should either incorporate continuous monitoring completely into the screening matrix or remove the long-term action levels from the separate continuous monitoring framework.

- **The rolling 7-day (short-term) and rolling 90-day (if they remain) action levels should be revised.** The proposed action levels are too low and therefore practically disincentivize the use of continuous monitors. Despite being the most frequent detection method (every 12 hours as proposed), the proposed short-term action levels of 15 or 21 kg/hr are both below 30 kg/hr, which is the detection threshold for the most frequent periodic screening technology (monthly). A typical minimum threshold for actionable detection and notification is 20 kg/hr for today's technology. The lower the action level, the higher uncertainty on which source is causing the detection, and the likelihood for monitors to detect permitted or other background emissions. One potential solution is to have the short-term action level based on a fixed level to address smaller sites (e.g., wellhead only sites) or a variable level from baseline emissions (e.g., 200% of baseline emissions) to address larger sites.

  The long-term 1.2 or 1.6 kg/hr action levels may also be below the baseline emissions for many sites, which would be especially problematic if they represent total site emissions. Some operators, therefore, would effectively be unable to adopt continuous monitoring for NSPS OOOOb or EG OOOOc compliance.

3.4.6 We support timely and flexible follow-up actions to address any leaks found and request similar repair timeframes consistent with §60.5397b and §60.5416.

API supports the flexible language proposed in §60.5398b(c)(6) that describes initiating an investigative analysis to determine the primary reason for the emissions detected. We believe an operator can perform this investigation in numerous ways including using site-specific data. Due to the various ways that continuous monitors may be used for emissions detection, different follow-up actions may be appropriate for this technology when compared to AVO, OGI, or Method 21. While we appreciate the flexibility, we offer the following suggestions so that follow-up actions do not disincentivize the use of continuous monitoring as discussed more generally in Comment 3.1.7:

- **The timeline for initiating the investigative analysis should be extended from 5 calendar days to 5 business days.** Similar to periodic screening, additional time is needed for data validation.

- **EPA should clarify that the investigative analysis and corrective actions can be conducted remotely where feasible.** Operators should be able to conduct an initial evaluation of detected emissions based on SCADA or other operational data rather than sending a person to the site. Due to safety and cost concerns, operators typically limit the amount of time in the field. Remote investigative analysis and corrective actions could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to an onsite analysis required for each instance of detected emissions.

- **EPA should also clarify that limited or full site follow-up OGI surveys should be allowed in response to emissions detected by continuous monitoring depending on the localization performance of the continuous monitor(s)**. A limited or full site follow-up OGI survey may be a useful tool in identifying the source of emissions and therefore appropriate corrective actions. API recommends that the proposed follow-up action process for periodic screening surveys based on localization performance also apply to continuous / near continuous monitoring; refer to Comment 3.3.2 and Figure 2 for more details.

- **The timeline for completing the investigative analysis and initial corrective actions should be 30 days, not 5 days as proposed.** Follow-up actions for continuous monitoring should be consistent with repair timelines for OGI inspections.

- **Consistent with our suggestions in Comment 3.2, we suggest all references to "root cause analysis" be amended to "investigative analysis".**

4.0 Associated Gas Venting from Oil Wells

API recognizes the environmental benefit of eliminating the venting of associated gas from oil wells that do not currently recover gas to a sales line, for injection, or for onsite fuel as its primary use. We disagree with EPA's approach to the control standards proposed including the level of recordkeeping and reporting as it far exceeds the normal level of compliance assurance typically expected from an NSPS. An initial analysis[25] of the impact of the rule on potential production indicates that if the final rule were to eliminate flaring of associated gas, or is implemented in such a way that the practical effect is to eliminate flaring of associated gas, it could result in a substantial loss to production. Such a restriction or implementation would not be supported by API. Should the final rule either expressly or practically eliminate flaring of associated gas, it could be technically infeasible and not cost effective.

We offer the following suggestions with the belief that it is possible to create a manageable regulatory framework that targets the emissions from associated gas at areas without gas gathering infrastructure, including practical compliance assurance, recordkeeping, and reporting.

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[25] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API's request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

4.1 We support recovering gas to sales, for reinjection, used as onsite fuel, or routing gas to a control device. We do not support the additional certifications against emerging technologies prior to flaring associated gas.

We continue to support how EPA had described the proposed requirements for associated gas from oil wells in their November 2021 preamble description, but we do not support the hierarchy of the compliance options and associated recordkeeping and reporting requirements as proposed and believe the requirements should be technology neutral. Specifically, we support:

- Recovering gas to sales in §60.5377b(a)(1) (see also Comment 4.2).
- The beneficial use of the associated as onsite fuel proposed in §60.5377b(a)(2).
- Reinjection of the recovered gas into the well or injection of the recovered gas into another well for enhanced oil recovery proposed in §60.5377b(a)(4).
- Flaring the gas such that 95% control efficiency is achieved as proposed in §60.5377b(b).
- An annual reporting requirement focused on periods of venting.

We do not support the requirement to make an infeasibility demonstration and safety and technical certification statements in order to use a flare to reduce these emissions[26]; especially at oil wells that are connected to gas gathering infrastructure and only temporarily flare gas when unable to sell the gas (see also Comment 4.2). We also note that EPA even uses controlling associated gas with a control device such as a flare as justification for the storage vessel requirements (87 FR 74793) *"…these sites also may be subject to standards for oil well with associated gas and the compliance burden is shared between those affected facilities to ensure emissions from both storage vessels and oil wells with associated gas are reduced by 95 percent."* This statement is evidence of EPA's clear expectations of the use of flares at oil well facilities that may have associated gas, making the need for these additional demonstrations arbitrary.

While we support the concept of other types of beneficial use proposed in §60.5377b(a)(3), we do not support the list of options proposed in §60.5377b(b)(1) (methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas). Each option listed requires specialized equipment, capital investment, and additional energy to implement the technology that would generate emissions, some of which may be greater than flaring the associated gas directly. Furthermore, the cost-benefit of the proposed hierarchy of requirements has not been adequately justified by the EPA. In fact, EPA has not considered the technical feasibility, costs, or benefits from any of these options in the updated Technical Support Document[27].

4.2 The provisions for associated gas at oil wells that primarily recover associated gas to sales, for injection, or used for onsite fuel must be adequately delineated from associated gas from oil wells that do not have adequate or accessible gas gathering infrastructure.

Specifically, the notion that *"recovering associated gas from the separator and routing the recovered gas into a gas gathering flow line or collection system to a sales line"* constitutes a control option as proposed under

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[26] If retained, the infeasibility demonstration that is a prerequisite to control of associated gas must include consideration of commercial availability of alternatives to pipeline injection and of site economics. Consider, for example, the World Bank's "Zero Routine Flaring by 2030," which seeks "to implement economically viable solutions to eliminate [routine] flaring [of associated gas] as soon as possible."

[27] Supplemental TSD Chapter 6 Associated Gas October 2022 / EPA-HQ-OAR-2021-0317-1578_attachment_7.xlsx

§60.5377b(a)(1) is exceptionally problematic since this explains standard business operations for thousands of wells producing a vital energy resource throughout the country. Including this option within the proposal creates tremendous administrative burden in maintaining the records proposed in §60.5420b(c), without generating environmental benefit as the gas is typically being captured to a sales line already. Selling natural gas is part of our business and this sets a uniquely unjustifiable precedent since operators are in the business to sell as much of the produced gas as possible. In the preamble (87 FR 74779), EPA states *"In addition…a significant addition to the proposed rule is the establishment of requirements for situations when associated gas from an oil well that is primarily either routed to a sales line or used for another beneficial purpose is unable to utilize the gas in that manner due to gathering system or other disruptions."* We agree that these wells should have special requirements for the sporadic, short periods of time that gas cannot be recovered, but the current provisions proposed in §60.5377b(a) do not adequately address associated gas that is typically recovered.

For wells where associated gas from the separator is designed and configured to be recovered, we support simplification of the requirements that focus on the short periods of time when gas is not recovered for sale, injection, or reuse. Specifically, we support flaring the gas by using a permanent or temporary control device[28] that achieves 95% efficiency during periods of time when the associated gas is routed to the control device. In this scenario when a well that is configured to route gas to sales or for reinjection can no longer recover the gas for its primary use, the gas should be immediately routed to the flare as soon as practicable. Since EPA has already acknowledged in the preamble (87 FR 74780) that these situations do occur and are outside the control of the well operator, we do not support making technical or safety demonstrations where disruptions or interruptions in the gas gathering infrastructure result in the need to route the associated gas to a control device for temporary periods. For wells that primarily recover gas for reinjection, conducting compressor maintenance may necessitate temporary periods of flaring. This is reasonable given that a facility is designed with a certain configuration for handling the disposition of associated gas and it is unreasonable to expect facilities to design for multiple uses based on emerging technologies before they can resort to flaring; especially during these short intermittent periods.

Any retention of technical demonstrations, for wells that do not primarily recover associated gas, should include economic viability.

4.3 EPA should include a definition for associated gas.

EPA did not include a defintion of associated gas within §60.5430b or §60.5430c, which we do not believe was EPA's intent. Within the preamble[29] EPA uses the following language when describing associated gas. We believe this language with a few additional clarifications would be appropriate to clearly describe associated gas from oil wells for the purposes of NSPS OOOOb and EG OOOOc. The distinctions we provide explicitly determine which separator the requirements proposed in §60.5377b(a) would apply, providing clear transparency for the regulated community.[30]

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[28] A temporary control may be needed in certain situations that an operator may not have planned for or may not have expected. . Allowing both permanent or temporary flare provides flexibility for locations where an existing permanent control device cannot be used or where has not yet been installed.

[29] 87 FR 74778

[30] Without a clear definition, there is uncertainty of what gas EPA seeks to control. For example, some members debate if EPA meant to include flaring from storage vessels. By limiting to the first stage of separation, operators will clearly know what associated gas is applicable.

> *Associated gas means the natural gas which originates at oil wells operated primarily for oil production and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon during the initial stage of separation after the wellhead.*

4.4 Using associated gas as purge or pilot gas for a control device should be considered beneficial use.

Pilot and/or purge gas allow flares and other control devices to operate safely and effectively to reduce emissions. Furthermore, NSPS OOOOb and EG OOOOc require flares and enclosed combustion devices to have a continuously burning pilot flame when the flare is in use. Enclosed combustion devices are also required to maintain a minimum inlet flow rate, which may require supplemental fuel. In other words, pilot and purge gas are part of the fuel requirements for a flare or enclosed combustion device and are not controlled vent streams.

Since the use of associated gas as an onsite fuel source is one of the proposed beneficial use options in §60.5377b(a)(2), we request that EPA clarify that purge or pilot gas for a control device is considered part of onsite fuel use as shown in the following suggested edit to §60.5377b(a)(2):

> *Recover the associated gas from the separator and use the recovered gas as an onsite fuel source, which may include using the recovered associated gas as purge or pilot gas for a control device or flare.*

As an alternative, EPA could clarify that purge or pilot gas for a control device is considered a useful purpose option under §60.5377b(a)(3).

4.5 Special considerations for handling associated gas from wildcat and delineation wells

In our January 31, 2022 comment letter, we asked EPA to allow certain provisions for wildcat or delineation wells in its proposal with respect to the associated gas from oil well provisions. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. In many instances an operator will not know or understand the composition of the gas until after the well is drilled. EPA has acknowledged this fact within the definitions that have been published in §60.5430a and maintained in the proposed §60.5430b & §60.5430c where the terms are defined as:

> *Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.*
>
> *Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.*

In response to our January 31, 2022 comment letter, EPA stated (see 87 FR 74780):

> *"The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for these situations due to lack of specific sufficient information. Therefore, the EPA is interested in additional information on gas compositions of associated gas that would make it both unusable for a beneficial purpose and unable to be flared. The EPA is not only interested in why commenters feel these situations warrant an exemption from the associated gas standards as proposed, but also*

> *what methods are currently in use, or could be used, to minimize methane and VOC emissions in these situations."*

Like provisions within NSPS OOOOa for well completions, EPA should allow special considerations for handling associated gas since these activities are exploratory in nature and are typically not located near existing infrastructure. Wildcat or delineation wells will typically only produce for short period of time after flowback ends in order to complete well testing where the production flow rate is determined along with other parameters such as the gas composition before the well is shut-in or capped, which is regulated based on state protocols.[31] These wells are typically located in remote locations far from any form of permanent infrastructure thereby disallowing any beneficial reuse from a practical and logistical standpoint since the gas composition is not known.

As an example, on the Alaskan North Slope, ice roads must be built to access locations where exploration activities are taking place because roads do not exist, and there is not access/connection to existing oil and gas infrastructure. As we described above, characteristics of associated gas from these wildcat / delineation wells is unknown and therefore it is not wise to use as an onsite fuel source. Currently under NSPS OOOOa and under proposed NSPS OOOOb, the initial well flowback is subject to the well completion operation requirements, which allow for use of a completion combustion device. After the flowback ends, the well undergoes cleanout and a well test (extended flowback) is conducted to determine reservoir characteristics. There will still be open top tanks and a combustion device present; however, this equipment will only be utilized for a very short duration. The compliance requirements for both the provisions in §60.5377b(a) or §60.5412b do not allow for realistic implementation for such unique and short-term operations which are not permanently producing oil from a well.

Since wildcat or delineation wells will typically cease production in well under 180 days[32], a temporary or portable combustion device similar to those used to control emissions from well completions is appropriate to reduce VOC and methane emissions. We therefore request EPA allow any associated gas produced from wildcat or delineation oil wells be routed to a completion combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways). Due to the temporary nature of these activities, the control device compliance requirements should mimic the requirements of control devices utilized for well completions affected facilities, i.e., operated with a reliable continuous pilot flame and no further compliance requirements.

Suggested Redline for inclusion within §60.5377b:

> *For each wildcat or delineation oil well with associated gas at a well affected facility, capture and direct recovered associated gas from the separator to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

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[31] EPA determined well testing "*conducted immediately after well completion, is considered part of the well completion*" for the purposes of reporting emissions under the Greenhouse Gas Reporting Program (see definition of Well Testing Venting and Flaring in §98.238).

[32] We note the initial performance test for enclosed combustion devices not tested by a manufacturer would not be required until within 180 days after initial startup or start of production. Wildcat or delineation wells typically do not produce for this long to warrant compliance with these provisions. Furthermore, duration of well testing flowbacks from wildcat and delineation wells can be limited to 30 days per other agency regulations/guidance, e.g. BLM's NTL-4A guidance (and proposed Waste Prevention rule) generally limits this activity to 30 days, extension beyond 30 days requires additional approval by the agency.

4.6 EPA's Model Plant Analysis Assumptions

Based on preliminary review of EPA's technical support document that was issued in conjunction of the Supplemental Proposal, the associated gas model plant analysis does not include assumptions reflective of actual proposed requirements.

- In our January 31, 2022 letter, we stated *"a more representative cost for installing a flare suitable to control associated gas would be $100,579, based on the average costs EPA uses for analyzing storage vessel controls."*[33]. We also stated, *"that we did not include the costs from EPA's Workbook 'MP1 Plus Monitors.xlsx' as this would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the proposal. If EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA's cost analysis."* In the Supplemental Proposal EPA has proposed additional parametric monitoring but has not included these costs in the analysis.

- The EPA should consider model facilities that have existing control devices but now need to install the correct flow and other parametric monitoring equipment as this would be a type of model plant scenario not evaluated by the EPA.

- None of the beneficial reuse emerging technologies have been included within the model plant analysis. It is unclear how EPA has justified the inclusion of these technologies related to costs, feasibility or environmental benefit/disbenefit.

- EPA includes no costs associated with the technical demonstrations proposed. There are direct costs associated with the engineering certification process, whether companies support in-house engineers or leverage third parties. In previous API comments we have provided to the EPA, we estimated certifications to be $2,000 - $9,000.[34]

- The EPA seems to bias the data selected for baseline emissions to fit their expectation and not based on actual reported data. In section 6.3.1 of the technical support document[35] EPA states,

  > *There were 95 facilities/basins that reported associated gas venting emissions [through GHGRP subpart W data]. For each facility/basin, the number of wells venting is reported, along with the total methane vented from all wells. For each facility/basin, we calculated the average emissions per well. These average well emissions ranged from 0.015 tpy to over 2,400 tpy. Almost 20 percent of the facilities/basins had average well methane emissions less than 0.2 tons per year. Explanations of the specific causes of emissions is not provided in the GHGRP subpart W outputs, but it would be expected that routine venting of associated gas would result in emissions greater than this level. In order to avoid selecting a well associated gas venting level that was unreasonably low, a weighted average well emissions level was calculated, using the total emissions from the facility/basin as the weighting factor. The result is an estimated average*

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[33] EPA-HQ-OAR-2021-0317-0039
[34] EPA-HQ-OAR-2017-0801
[35] EPA-HQ-OAR-2021-0317-1578

> *annual methane emissions level of 344 tpy. Applying the representative composition yields a representative VOC emissions level of 96 tpy.*

Within these statements, EPA acknowledges that there are very low methane emissions generated from wells that only temporary flare associated gas when the primary recovery method is not available (i.e. routing to sale, for injection, or used as onsite fuel). However, the EPA in this proposal has not made the distinction between facilities that temporarily flare versus those that are truly stranded.

5.0 Control Devices, Covers and Closed Vent Systems

API supports EPA's decision to maintain the 95% control efficiency standard for control devices within NSPS OOOOb and EG OOOOc, and we acknowledge EPA's desire to assure proper control device performance. The following recommendations will allow this goal to be achieved more effectively at well sites, centralized production facilities, compressor stations, and natural gas processing plants. Specifically, the proposed control device and cover and closed vent system requirements present technical feasibility, timing, and cost issues. To address these concerns, NSPS OOOOb and EG OOOOc should allow for more cost-effective monitoring alternatives and better alignment between monitoring requirements for manufacturer-tested enclosed combustion devices and other enclosed combustion devices. Comments concerning both control devices and closed vent systems are presented in this section.

5.1 Emissions detected from covers and closed vents system do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

EPA states in the Preamble that when a leak is detected in a cover or a closed vent system during a fugitive emissions survey, alternative screening survey, or by a continuous monitoring system, "*the emissions would be considered a violation of the [no identifiable emissions] standard and thus a deviation*"[36]. The "no identifiable emissions standard" or NIE standard is a design and work practice standard (***emphasis added***).

> *You must **design and operate** the closed vent system with no identifiable emissions as demonstrated by §60.5416b(a) or (b), as applicable.37*

As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. EPA has presented no reason in the Proposal to depart from its historical approach regarding fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in

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[36] 87 FR 74804

[37] §60.5411b(a)(3)

compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed.

A “no identifiable emissions” or “no detectable emissions” standard cannot constitute a numerical emissions limitation since BSER must be achievable, so the standard must be applied as a work-practice standard. Even the most well-designed and operated system will develop a leak due to wear and tear on equipment. A zero emissions standard for cover and closed vent system components is practically unachievable because some leaks will happen in the normal course of operations (e.g., typical fugitive leaks) and some develop due to causes beyond an operator’s control. Consider that if a leak from a rusty bolt on a pipe flange is only subject to the standard LDAR work practice standard, then a leak from a rusty bolt on a cover or closed vent system should also only be subject to the standard work practice standard. There is no reason why a typical fugitive leak should be treated differently simply because it occurs on a cover or closed vent system.

Additionally, a leak may develop due to malfunctions or a foreign object (e.g., sand or dust), both of which are not reasonably within the control of the operator. Such leaks are not caused by inadequate design or improper operation and cannot constitute a violation of the “no identifiable emissions” standard. API recognizes the possibility of improperly operating a cover or closed vent system (e.g., forgetting to close a thief hatch), but EPA should clearly differentiate these types of leaks from those described above. For these reasons, EPA’s application of the standard as a numerical emission limitation is not only unachievable but will also have will have a chilling effect on companies that aim to do voluntary leak surveillance, and disincentivize the use of more sensitive instruments. EPA should encourage and incentivize operators to conduct additional voluntary monitoring without the fear of an automatic violation if a leak is detected from a cover or closed vent system.

Lastly, CAA § 111(h)(2) provides that a work practice standard should be prescribed in lieu of a standard of performance (i.e., numeric emissions limitation) when “a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant.” That is precisely the case with EPA’s proposed NIE standards. The NIE standards do not apply to emissions from the storage vessel or equipment to which the closed vent system is installed. Rather, the proposed NIE standard applies to the closed vent system itself. In this case, it is obvious that there is no “conveyance” through which the regulated pollutants would be emitted or captured. To accomplish such an outcome, the closed vent system to which the NIE standard applies would have to be enclosed within another closed vent system or similar permanent total enclosure in order for the regulated emissions to be captured for subsequent control or venting. Requiring such a system would be inordinately costly, highly impracticable, and likely impossible. This is precisely why LDAR standards have been expressed from the inception of such programs almost exclusively as work practice standards. In short, the NIE standard cannot be effectively construed as a zero-emissions standard, as EPA proposes, because no “conveyance” exists that allows for capture of the regulated emissions and application of such a standard to an emissions point.

5.2 Supply chain delays for acquiring flow meters or other monitoring equipment necessitates the initial compliance period must be extended to at least one (1) year after publication in the Federal Register.

Due to EPA’s proposed designation of the applicability date aligned to the November 2021 proposal (see Comment 12.1), operators may not have the adequate flow and net heating value monitoring technology in place for all sites subject to the provisions proposed in NSPS OOOOb, because these additional monitoring requirements were only contemplated but not specifically proposed in that initial proposal. Since EPA’s proposal for consistent control device monitoring requirements regardless of the affected facility will apply to both NSPS

OOOOb and EG OOOOc, the number of control devices subject to monitoring requirements will increase significantly. The current supply chain delay for acquiring flow meters or similar monitoring equipment is currently approximately 6 to 8 months. This delay within the supply chain is expected to be exacerbated based on both NSPS OOOOb and EG OOOOc implementation over the coming years.

In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk.Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap.

As an alternative, a site shutdown to install control device monitoring equipment will result in emissions from the shutdown and purging of equipment and piping. Shutdowns at midstream compressor stations or gas plants could result in gas venting, gas flaring, or a shut-in at upstream facilities. A shorter compliance period will multiply these disruptions as operators work to comply with NSPS OOOOb.

In the 2012 NSPS rule[38], EPA allowed implementation for storage vessel requirements to be phased-in to accommodate the vast number of affected facilities and the number of control devices that would be needed to be acquired. Other state rules, such as those in Colorado and New Mexico[39], have allowed for an orderly phase-in period for certain requirements. EPA must consider that a similar compliance schedule is warranted in the proposed NSPS OOOOb and EG OOOOc based on similar constraints and concerns for acquiring the appropriate monitoring equipment that has historically been exempt from control devices for storage vessel affected facilities. The current supply chain delays in acquiring equipment and limited resources to install equipment are expected to be exacerbated by the large number of control devices subject to monitoring under NSPS OOOOb or EG OOOOc.

Based on feedback from members, we request the initial compliance period for control device flow and net heating value monitoring requirements be extended from 60 days after final publication in the Federal Register to at least 1 year after publication in the Federal Register to allow operators time to order and install the necessary meters assuming that the applicability is based on the December 6, 2022 and other our comments concerning reconstruction and modification are addressed. Additional time, at least another year, would be required if the rules are finalized as proposed. Specifically, compliance with the flow and net heating value monitoring requirements at §60.5417b(d)(1)(vii)(A), §60.5417b(d)(1)(viii)(B), and §60.5417b(d)(1)(viii)(D) along with related operational requirements must be extended to allow operators adequate time to procure and install the necessary monitoring equipment where appropriate as various new equipment is installed, or other equipment is modified or reconstructed.

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[38] See EPA's response at 77 FR 49525-49526.

[39] 20.2.50.122.B(3) NMAC and 20.2.50.123.B(1) NMAC

5.3 With the increased number of control devices subject to flow monitoring requirements, the accuracy requirement for flow meters should be ±10% of maximum expected flow.

For manufacturer-tested enclosed combustion devices, EPA is maintaining the current flow monitoring accuracy requirement of ±2% or better[40]. Historically, this requirement only applied to control devices for wet seal centrifugal compressors and was not required for control devices used to reduce emissions for other affected facilities under NSPS OOOO or NSPS OOOOa. Vent gases from centrifugal compressors have relatively stable flow rates while vent gas from storage vessels is intermittent, low pressure, low velocity / flow, and more difficult to measure.

Since EPA is proposing consistent control device monitoring requirements regardless of the affected facility controlled for both NSPS OOOOb and EG OOOOc, the number of control devices subject to flow monitoring requirements will increase significantly under NSPS OOOOb and EG OOOOc.

The ±2% accuracy requirement may not be technically feasible for most commercially available meters nor cost-effective for control devices on every affected facility at well sites, central production facilities, compressor stations, and natural gas processing plants. As mentioned in Comment 5.2, the availability and cost of meters are negatively affected by supply chain constraints and limited resources to install them. API has previously commented[41] on the challenges with flow monitoring at upstream facilities. This level of accuracy is also more stringent than the ±5% accuracy requirement for flare vent gas flow rates at velocities above 1 feet per second under Maximum Achievable Control technology (MACT) standards finalized under 40 CFR 63 SubpartCC (RMACT)[42].

Two types of commercially available flow meters that are commonly used are thermal dispersion meters or ultrasonic meters. Ultrasonic flow meters are the only identifiable meter that can achieve the ±2% accuracy, but this accuracy may decrease under low-flow or low-pressure conditions. While these meters are technically feasible to meet the proposed accuracy requirement, they may not be economically reasonable with an estimated cost of $20,000 to $30,000 each. In EPA's cost analysis for storage vessels controls[43], the cost of a flare with monitoring equipment was estimated but was not used in the subsequent BSER analysis for new or existing sites. Therefore, EPA did not fully consider the cost-effectiveness of the proposed monitoring requirements for control devices. Thermal dispersion flow meters are less expensive but may not meet the accuracy requirement with a typical accuracy of ±5% or better at high flows (accuracy decreases at pressures less than 25 psig). The lower pressure and variable flow rates from certain affected facilities such as storage vessels also make the accuracy requirement difficult to meet. If a control device is used for controlling atmospheric storage tanks only, it will be operating at less than 25 psig and so even a ±5% accuracy may be difficult to achieve; therefore, the flow meter accuracy requirement must consider this likely scenario. In colder conditions, like those experienced in North Dakota and other states, the liquid drop out caused by condensation can also reduce the accuracy of flow meters and make an accuracy of ±2% technically infeasible. Therefore, API proposes that the accuracy for control device inlet flow rate be increased to ±10% of maximum expected flow.

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[40] §60.5417(d)(1)(viii)(A) and §60.5417a(d)(1)(viii)(A)

[41] API's December 4, 2015, comments on the proposed Subpart OOOOa and January 31, 2022, comments on the proposed Subparts OOOOb and OOOOc.

[42] 40 CFR 63 Subpart CC Table 13

[43] EPA-HQ-OAR-2021-0317-0039, "StTanks_Control_Costs_v5.1.xlsx" and "EPA_Flares_Calc_Sheet_MP1plusmonitors.xlsx"

5.4 Flow monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices.

Manufacturer-tested enclosed combustion devices function similarly to other enclosed combustion devices with the only difference being the party responsible for stack testing; therefore, the proposed flow monitoring requirements should be consistent regardless of whether the device is tested by the manufacturer or owner/ operator. In comparing the proposed flow monitoring requirements for manufacturer-tested enclosed combustion devices at §60.5417b(d)(1)(vii)(A) and other enclosed combustion devices at §60.5417b(d)(1)(viii)(D), the following inconsistencies were noted and should be addressed.

- **No accuracy requirement is specified for other enclosed combustion devices.** As discussed above, the accuracy requirement for flow rate monitoring should be ±5% for both manufacturer-tested and other enclosed combustion devices.
- **Manufacturer-tested devices appear to be limited to flow meters while other enclosed combustion devices may use other parameter monitoring systems.** Other parameter monitoring systems combined with engineering calculations should also be an option for flow monitoring on manufacturer-tested devices especially considering the potential challenges in obtaining and installing a flow meter in a timely fashion. Other parameter monitoring systems are also needed in situations where flow monitoring is infeasible (e.g., low flow scenarios). These other parameter monitoring systems would be more stringent than MACT HH, which allows GRI-GLYCalc™ or other process simulation to calculate inlet flow rate for manufacturer-tested control devices[44].
- **Manufacturer-tested devices do not have an option to exempt the device from flow monitoring.** For enclosed combustion devices not tested by the manufacturer, maximum inlet flow rate monitoring is not required if a demonstration can be made using engineering calculations, and minimum inlet flow rate monitoring is not required if a backpressure valve is properly installed and operated. These alternative compliance options for flow rate monitoring should also be available to manufacturer-tested devices.
- **EPA should clarify that a backpressure preventer is a backpressure valve.** Since backpressure preventer is an unclear term, EPA should use the term “backpressure valve” instead.
- **Additional examples of other parameter monitoring systems should be added to the regulatory text.** To clarify and elaborate on the variety of other parameter monitoring systems that could be used in lieu of a flow meter, EPA should consider adding inlet pressure and line size as additional examples in the regulatory text.

Based on these items, API offers the following recommended redline of flow monitoring requirements for manufacturer-tested control devices in §60.5417b(d)(1)(vii)(A):

> *Except as noted in paragraphs (d)(1)(vii)(A)(1) through (4) of this section, ~~T~~the continuous parameter monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ~~±2~~ ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The flow rate at the inlet to the combustion device*

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[44] §63.773(d)(3)(i)(H)(*1*)

> *must be equal to or greater than the minimum flow rate and equal to or less than the maximum flow rate determined by the manufacturer.*
>
> *(1) If you can demonstrate, based on the maximum potential pressure of units manifolded to the control device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the control device cannot cause the maximum inlet flow rate determined by the manufacturer to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.*
>
> *(2) If you install and operate a backpressure valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.*
>
> *(3) Control devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*
>
> *(4) Pressure-assisted flares control devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

API also offers the following recommended redline of flow monitoring requirements for control devices not tested by the manufacturer in §60.5417b(d)(1)(viii)(D):

> *Except as noted in paragraphs (d)(1)(viii)(D)(1) through (4) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustor or flare. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement.*
>
> *(1) If you can demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustor cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section or the flare tip velocity limit in §60.18 to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.*
>
> *(2) If you install and operate a backpressure ~~preventer~~ valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.*
>
> *(3) Flares that are exempt from maximum inlet gas flow monitoring and enclosed combustion devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*
>
> *(4) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

Given the small size, dispersed nature, and large number of units affected by this rule, these changes would appropriately reduce the burden of compliance while still providing for compliance demonstration and monitoring.

5.5 EPA must provide the minimum inlet flow rate for current manufacturer-tested control devices no later than publication of the final rule so that owners and operators are able to achieve compliance.

In the preamble[45], EPA states that previously tested manufacturer control devices "*would not need to perform new performance tests*" and "*[t]he zero-level at which the combustion control device was tested will be extracted from the previously submitted performance test report and added to the information on the EPA's website*". This minimum flow rate information must be added to the EPA's website[46] no later than publication of the final rule since owners and operators cannot extract the information themselves as the underlying test reports are not currently available on the website. This minimum flow rate information may also not be easily obtained from the manufacturer directly. EPA must provide this minimum flow rate information no later than publication of the final rule so that owners and operators are able to take any necessary action (e.g., purchase of a different control device or operational changes) to achieve compliance. If the minimum flow information is not provided by the publication of the final rule, EPA should consider implementing a longer initial compliance period (see Comment 5.2).

5.6 EPA should allow the use of alternative technologies within the proposed monitoring requirements.

Given the increasing number of control devices subject to proposed monitoring requirements, EPA should allow the use of alternative technologies to meet the monitoring requirements for visible emissions, continuous pilot flame, and minimum net heating value. Well sites, centralized production facilities, and compressors do not have the same utilities and instrumentation resources as refineries, so alternative technologies would provide more cost-effective monitoring of control device performance.

5.6.1 A smoking check should be the primary monitoring method for visible emissions from flares and enclosed combustion devices.

Thousands of flares and enclosed combustion devices will be subject to proposed monthly Method 22 observations and associated recordkeeping. Each of these observations requires 15 minutes and detailed records to document that the observation was conducted according to Method 22. In total, these observations will add up to hundreds to thousands of hours each month and thousands to tens of thousands of hours per year with no added environmental benefit if the device is operating properly. Compliance can more easily be monitored using a monthly smoking check with a record documenting the time of the observation and whether the control device is observed to be smoking. If the device is observed to be smoking, then operator would be able to either 1) assume the device failed the visible emissions requirement and immediately take corrective actions or 2) conduct the 15-minute Method 22 observation to determine whether the device meets the visible emissions requirement. A monthly smoking check could reduce the time required to monitor the device by more than 90%, and this saved

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[45] 87 FR 74796

[46] https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers

time could be used for other tasks with greater environmental benefit (e.g., conducting a required AVO and/or OGI survey while at the site).

5.6.2 Video camera systems should be allowed as an alternative to Method 22.

Since some sites are already equipped with video camera systems, EPA should also allow video cameras as an alternative method to conduct the required monthly smoking check or Method 22 visible emission observations for enclosed combustion devices and flares. Video camera systems are allowed as an alternative to Method 9 observation under Broadly Applicable Approved Alternative Test Method ALT-82[47]. Although these video camera systems have similar supply challenges to other monitoring equipment (see Comment 5.2), they should be an allowed monitoring alternative. To be consistent with the smoking check or Method 22 requirement, the camera would be used to remotely conduct a smoking check and/or 15-minute observation for visible emissions from the control device every month. Owners or operators would keep a record of this remote visible emission observation with similar information required for in-person smoking check or Method 22 observation. Artificial intelligence and machine learning should be allowed to continuously screen the video feed for smoke detection and if smoke is detected, alert the operator that a Method 22 follow-up is required. Making the requirements for video camera systems more stringent than the proposed monthly Method 22 observation would disincentive the use of this alternative. Recordkeeping and reporting of additional video records could pose potential security risks and data storage concerns.

5.6.3 An automatic ignition system with a flame monitoring device should be allowed as an alternative to a continuous pilot flame.

A continuous pilot flame requires propane or other supplemental fuel at sites without fuel gas. For sites with sour gas, a continuous pilot flame requires either using the sour gas as the pilot or bringing in propane or other supplemental fuel to supply the pilot. Burning propane or other supplemental fuel is costly and generates additional emissions when no vent streams are sent to the control device. Similarly, burning sour gas generates additional emissions including SO_2 and potentially uncombusted H_2S. Some state rules, such as New Mexico[48] and Texas[49], allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. Therefore, API proposes that an automatic ignition system with a flame monitoring device be allowed as an alternative to a continuous pilot flame.

5.6.4 The minimum net heating value demonstration should be simplified.

EPA should provide flexibility to operators by simplifying its proposed minimum net heating value demonstration alternative to continuous net heating value monitoring. Both the proposed continuous net heating value monitoring and demonstration alternative seem excessive considering that the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirements. These vent streams consist of mostly hydrocarbons, and the simplest hydrocarbon (methane) has a net heating value of approximately 900 Btu/scf, which is 450%, 300%, or 112% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf depending on the type of control device.

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[47] https://www.epa.gov/sites/default/files/2020-08/documents/alt082.pdf

[48] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(b) NMAC

[49] 30 TAC §106.492(1)(B)

The proposed minimum net heating value demonstration requires continuous monitoring over 10 days or a minimum of 200 hourly samples of inlet gas to the flare or enclosed combustion device. EPA's justification for such an extensive sampling campaign is *"to provide a large sampling set by which to assess the variability of the vent gas sent to the combustion device and to adequately characterize the tails of the distribution."*[50] EPA did not provide additional detail as to why it expects the distribution of vent gas composition to vary enough to potentially be below the required minimum net heating value. Such a large sampling set is unnecessary when the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirement.

Vent streams from oil well with associated gas, centrifugal compressor, and pneumatic controller in Alaska affected facilities are typically comparable to sales gas or natural gas. In AP-42, natural gas is listed as having a gross heating value of 1,020 Btu/scf (Section 1.4) or 1,050 Btu/scf (Appendix A). The "2011 Gas Composition Memorandum"[51] used in EPA's TSD also suggests net heating values well above the required minimum. Gas composition typically does not change unless certain actions occur at the site, such as adding a new well or refracturing an existing well. Even though the gas composition will typically change with new or modified well streams, composition remains well above the required minimum net heating value.

Vent streams from storage vessel affected facilities consist of more large hydrocarbons than sales gas and have a typical net heating value of 2,000 Btu/scf or more, which is 1,000%, 667%, or 250% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf, respectively. The addition of air from an open thief hatch could drop the heating value of tank vapors below the required minimum net heating value, but the proper operation of thief hatches and other openings are already addressed in the proposed cover requirements.

Vent streams from affected facilities that could potentially be below the minimum heating value requirement include compressors in acid gas service or those at Enhanced Oil Recovery (EOR) facilities. Both situations could have high carbon dioxide (CO_2) content which would lower the net heating value, so operators typically add assist gas or another vent stream with sufficient heating value to facilitate proper control device operation. In these limited situations, API proposes that flow monitoring of the assist gas and vent streams should be allowed as an alternative to the continuous monitoring of net heating value in these limited situations.

Since the vent streams from affected facilities are expected to have sufficient heating value, both the proposed continuous net heating value monitoring and demonstration alternative are economically unreasonable. Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000. These monitors may also experience operational issues with entrained liquids in the vent gas stream especially in colder climates and seasons. For the minimum net heating value demonstration alternative, the cost is expected to be $250,000 or more per demonstration. The cost of a vendor-conducted 10-day continuous monitoring campaign is estimated at a minimum of $250,000 to $275,000 while the cost of 200 hourly samples is estimated at a total of $300,000 to $400,000 with an average cost per sample of $1,500 to $2,000 including shipping and analysis.

Since EPA's proposed minimum net heating value demonstration is too onerous and costly, API proposes the following to provide operators the necessary flexibility to comply with net heating value requirements:

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[50] 87 FR 74795

[51] EPA-HQ-OAR-2010-0505-0084

- The 10-day demonstration be simplified to a single sample including the use of an appropriate, representative sample or an initial flare compliance assessment with §60.18 using Method 18 of Appendix A. If a representative sample is used, the operator must document why the sample is characteristic of the vent stream composition. If the sample or §60.18 assessment demonstrates that the net heating value is at least 150% of the applicable minimum value (i.e., net heating value of the sample is at least 300, 450, or 1,200 Btu/scf, as applicable), net heating value monitoring would not be required. After the initial demonstration, continuous compliance would be demonstrated through subsequent samples once every 3 years. If the initial or subsequent sample is below 150% of the applicable minimum net heating value, the operator would be required to conduct more extensive sampling as proposed below or install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- If an initial or subsequent sample does not meet 150% of the minimum net heating value, operators should have the option to conduct a more extensive sampling event with a lower threshold. API proposes that this more extensive demonstration consist of a minimum of 2 hourly samples or 2 hours of continuous monitoring per day for 7 days for a total of 14 samples. The same number of samples is required for a comparable net heating value demonstration under RMACT[52]. Net heating value monitoring would not be required if all 14 hourly averages or samples are above 120% of the applicable minimum net heating value requirement. After the initial 7-day demonstration, continuous compliance would be demonstrated through a grab sample taken once every 3 years. If the initial or subsequent samples are below 120% of the applicable minimum net heating value, the operator would be required to install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- As with the proposed flow monitoring requirements, net heating value monitoring or demonstration alternative should not be required if operators demonstrate that the net heating value is never expected to below the minimum required value using applicable engineering calculations including process simulation software. This alternative would be similar to MACT HH, which allows GRI-GLYCalc™ or other process simulation software to be used to estimate benzene or BTEX emissions from a glycol dehydration unit[53]. Continuous compliance would be demonstrated through a grab sample taken once every 3 years to verify that the minimum net heating value is being met.

5.7 Minimum operating temperature and associated monitoring requirements should be revised.

NSPS OOOOb proposes a minimum operating temperature of 760 °C and temperature monitoring for enclosed combustion devices that demonstrate that combustion temperature is an indicator of performance during initial performance testing. Other enclosed combustion devices (i.e., those for which combustion temperature is not demonstrated to be an indicator of performance) would be subject to net heating value monitoring requirements. Given the increased number of control devices subject to NSPS OOOOb and EG OOOOc, EPA should revise the minimum operating temperature and associated monitoring requirements in the following ways:

- **Allow operators the flexibility to comply with either temperature or net heating value requirements for enclosed combustion devices that demonstrate that combustion temperature is an indicator of**

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[52] §63.670(j)(6)
[53] §63.772(b)(2)(i)

performance. Some enclosed combustion devices, such as thermal oxidizers, are designed with a minimum operating temperature while others are not. Even if a device can demonstrate that temperature is an indicator of performance during testing, maintaining a minimum operating temperature during actual operation may be challenging and require additional supplemental fuel due to the low or intermittent flow of the vent streams. As proposed, a minimum operating temperature with associated monitoring is the only option for enclosed combustion devices that demonstrate combustion temperature is an indicator of performance. For those enclosed combustion devices, operators should be able to comply with net heating value requirements as an alternative.

- **Allow the minimum operating temperature to be established by performance testing.** Rather than a fixed minimum operating temperature, EPA should allow operators the flexibility to comply with a default minimum operating temperature of 760 °C or the value established by the most recent performance testing. The enclosed combustion device may be able to demonstrate compliance at an operating temperature below 760 °C. Also, additional supplemental fuel may be required to keep the device at a minimum operating temperature of 760 °C when it could achieve a 95% control efficiency at a lower temperature. Operators should be allowed to conduct performance testing as needed to establish a new minimum operating temperature.

- **Allow a minimum operating temperature and temperature monitoring for manufacturer-tested devices.** As proposed, the minimum operating temperature and associated monitoring applies only to enclosed combustion devices not tested by the manufacturer. Like operators, manufacturers should be allowed to demonstrate that combustion temperature is an indicator of performance through performance testing and allow temperature monitoring as an option for demonstrating compliance. Operation and monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices like our recommendation on flow monitoring in Comment 5.4.

5.8 Manufacturer-tested enclosed combustion devices should continue to be exempt from periodic performance testing.

Under NSPS OOOO and MACT HH, manufacturer-tested control devices are exempt from periodic performance testing. Under NSPS OOOOa, manufacturer-tested control devices on centrifugal compressors are exempt from periodic performance testing if the device has continuous flow monitoring. NSPS OOOOb proposes that manufacturer-tested control devices be subject to both periodic performance testing and continuous flow monitoring. These requirements appear contrary to both the technical challenges in conducting performance tests in the field reiterated by EPA and the agency's intent stated in the preamble (***emphasis added***)[54],

> *''[w]e believe that testing units that are not configured with a distinct combustion chamber **present several technical issues that are more optimally addressed through manufacturer testing**, and once these units are installed at a facility, through **periodic inspection and maintenance** in accordance with manufacturers' recommendations.*
>
> *[Text omitted for brevity.]*

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[54] 87 FR 74794

> *For these reasons, we believe the manufacturers' test is appropriate for these control devices with **ongoing performance ensured by periodic inspection and maintenance**. ["] (76 FR 52785; August 23, 2011).*

Given EPA's previous rationale for manufacturer testing, the monitoring requirements proposed under NSPS OOOOb, and the increased number of control devices subject to these monitoring requirements, API recommends that manufacturer-tested control devices continue to be exempt from periodic performance testing.

5.9 Enclosed combustion devices subject to minimum operating temperature and temperature monitoring should also be exempt from periodic performance testing.

Under MACT HH, combustion devices are exempt from periodic performance testing if the device demonstrates during initial performance testing that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 °C. NSPS OOOO requirements[55] changed this exemption to devices that meet the outlet TOC performance level and that establish a correlation between firebox or combustion chamber temperature and the TOC performance level. NSPS OOOOa[56] adds a temperature monitoring requirement to the NSPS OOOO exemption for control devices on centrifugal compressors.

Like manufacturer-tested devices, NSPS OOOOb proposes to remove this exemption from periodic performance testing. As such, enclosed combustion devices that demonstrate during initial performance testing that combustion zone temperature is an indicator of destruction efficiency are subject to a minimum operating temperature, periodic performance testing, and temperature monitoring. Given the consistent monitoring requirements proposed under NSPS OOOOb and the increased number of control devices subject to these monitoring requirements, API proposes that enclosed combustion devices for which temperature is correlated with destruction efficiency be exempt from periodic performance testing.

To clarify the requested exemptions from periodic performance testing, API offers the following suggested redline of §60.5413b(b)(4)(ii):

> *You must conduct periodic performance tests for all control devices required to conduct initial performance tests, except ~~for a control device whose model is tested under, and meets the criteria of paragraph (d)~~ as specified in paragraphs (b)(4)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(4)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420b(b)(12).*
>
> *(A) A control device whose model is tested under and meets the criteria of paragraph (d) of this section.*
>
> *(B) A combustion control device demonstrating during the performance test under paragraph (b) of this section that combustion zone temperature is an indicator of destruction*

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[55] §60.5413(b)(5)(ii)(B)
[56] §60.5413a(b)(5)(ii)(B)

efficiency and operates at a minimum temperature of 760 °Celsius or the minimum temperature established during the most recent performance test.

5.10 The continuous monitoring option for organic compound concentration in the control device exhaust may not be technically feasible or economically reasonable. This monitoring option is also meaningless without the corresponding outlet concentration performance standard.

As an alternative to continuous flow monitoring and other similar monitoring requirements, EPA has retained the existing option under NSPS OOOO and OOOOa to use a continuous monitor for organic compound monitoring in the control device exhaust. However, such monitoring may not be a technically feasible or economically reasonable alternative to the other continuous monitoring requirements.

Furthermore, this monitoring option does not make sense since the previous TOC outlet concentration performance standard was not proposed for NSPS OOOOb and EG OOOOc. EPA should clarify if the removal of this alternate performance standard was intentional and how operators should handle compliance for existing control devices that are complying with the TOC concentration standard under NSPS OOOO or OOOOa.

5.11 Technical clarifications for proposed control device requirements.

5.11.1 EPA should clarify requirements for regenerative carbon adsorption systems that use a regenerant other than steam.

For some existing regenerative carbon adsorption systems, residue gas or another regenerant is used instead of steam since the sites typically do not have access to a steam system like a chemical plant or refinery. In the natural gas production and processing industry, natural gas (mostly methane) with a set of heat exchange systems is used to regenerate the carbon beds in place of steam. These systems can be used when there is potential to have air enter the system. A carbon bed does not have a direct fire source which can help limit the potential for a fire in the system. The regeneration cycle is infrequent for these systems. While the proposed requirements for regenerative carbon adsorption systems are unchanged from NSPS OOOOa, EG OOOOc will subject existing sources and control devices to methane standards, and API would like to confirm these regeneration cycles would not be part of the control requirements under this rule. Operators should not be forced to change the operation of their existing control device provided they meet the applicable requirements. Forcing sites to switch to steam regenerant may be technically infeasible or economically unreasonable.

5.11.2 EPA should clarify the proposed requirement language around the presence of pilot flames.

The proposed requirements for control device pilot flames use the following three phrases, each of which could suggest a different meaning:

- A **“continuous burning pilot flame”** means a pilot flame is required at all times regardless of whether the site is operating or vent gas is sent to the control device.

- A **"pilot flame present at all times of operation"** could mean either a pilot flame is required at all times the site is operating or only for those times when the control device is operating (i.e., vent gas is sent to the control device)

- **"Pilot flame while emissions are routed to the control device"** means a pilot flame is required only when vent gas is sent to the device (in other words, at all times of control device operation).

A pilot flame should only be required when emissions are routed to the control device since loss of the pilot flame would result in additional emissions only when vent gas is sent to the device. This clarification would allow for the use of automatic ignition systems (see Comment 5.6.3). This clarification would also be consistent with the compliance requirement found at §60.5412b(b)(1):

> *You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*

API offers the following redlines that clarify a pilot flame should be required only when emissions are routed to the control device like some state rules including New Mexico[57]:

> *§60.5412b(a)(1)(vii): You must install and operate a continuous burning pilot flame or automatic ignition system.*
>
> *§60.5412b(a)(3)(iv): You must install and operate a continuous burning pilot flame or automatic ignition system.*
>
> *§60.5413b(e)(2): A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*
>
> *§60.5415b(f)(1)(vii)(A)(1): A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(d)(1)(i): For an enclosed combustion control device that demonstrates during the performance test conducted under §60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You also must comply with the requirements of paragraphs (d)(1)(viii)(D) and (E) of this section, and you must install a monitoring device that continuously (i.e., at least once every five minutes) indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(d)(1)(vii)(B): A monitoring device that continuously, at least once every five minutes, indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.*

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[57] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(c) NMAC

> *§60.5417b(d)(1)(viii)(A): Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times while emissions from affected facilities are routed to the control device. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.*

> *§60.5417b(g)(1): A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in §60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot flame or combustion flame present for any time period while emissions from affected facilities are routed to the control device.*

> *§60.5417b(g)(6)(iii): There is no indication of the presence of a pilot flame or combustion flame for any 5-minute time period while emissions from affected facilities are routed to the control device.*

> *§60.5420b(c)(11)(i)(F)(1): Records that the pilot flame or combustion flame is present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*

5.11.3 EPA should clarify which elements of the control device monitoring plan apply to heat sensing monitoring devices that indicate the presence of a pilot flame.

The proposed control device monitoring plan requirement includes the following exemption: "…*Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements of this section.*"[58] However, one of the listed monitoring plan elements uses a thermocouple as an example. This example is confusing since thermocouples could be used as a heat sensing monitoring device for a pilot flame, or as a temperature monitoring device. In the former case, the exemption would apply but not in the latter. EPA should clarify which elements of the monitoring plan apply to heat sensing devices.

Therefore, API recommends the following redline for §60.5417b(c)(2)(ii):

> *Sampling interface ~~(e.g., thermocouple)~~ location such that the monitoring system will provide representative measurements.*

Alternatively, EPA could propose a different example for sampling interface.

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[58] §60.5417b(c)(2)

5.11.4 EPA should clarify that control devices are not considered fugitive emissions components and how to address emissions from control devices detected during fugitive emissions monitoring.

While EPA recognizes that “control devices should not be treated as fugitive emissions components”[59], EPA adds confusion by trying to address emissions “caused by a failure of a control device subject to §60.5413b” under the alternative periodic screening requirements. API believes that this requirement is intended to address improper control device operation such as an unlit flare when vent gas is routed to it and recognizes that alternative periodic screenings can be an effective tool at identifying such issues. However, such emissions are not fugitive emissions and would not necessarily be part of the follow-up ground-based monitoring survey of fugitive emissions components or inspections of the cover and closed vent system. Since control devices are required to meet a 95% control efficiency, they will always have the potential for uncombusted emissions that could be detected by OGI or alternative technology. Unclear or inappropriate requirements related to detected emissions from control devices may be a disincentive for the use of alternative leak detection technologies. Therefore, EPA needs to reconsider how to better address emissions from control devices that could be detected during fugitive monitoring surveys. Refer to Comment 3.3.2 and Comment 3.4.6 for API’s recommendations concerning follow-up action for alternative technologies.

5.12 Idle control devices at a site should be exempt from performance testing and monitoring requirements.

The proposed NSPS OOOOb and EG OOOOc requirements are unclear on whether idle control devices at a site are subject to performance testing and monitoring requirements. Some state rules, such as Colorado, require control devices be installed based on the potential maximum throughput of a site. For a site, the control devices may be installed and operated in series using pressure-activated valves, meaning that vent gas is sent to the first device until it reaches capacity before the excess vent gas is sent to the second device and so on. In actual operation, sites may never achieve the potential maximum throughput and associated emissions rates, so control devices toward the end of the control system are available but always idle. But even if activated, they would not be needed for purposes of complying with NSPS OOOOb or EG OOOOc.

One potential reading of the proposed NSPS OOOOb and EG OOOOc requirements is that such idle control devices are subject to initial and periodic performance testing and monitoring requirements especially if they are manifolded together. Conducting performance tests on idle control devices could increase in emissions since additional gas would need to be sent to the control devices for the purposes of testing or additional temporary piping installed to route vent gas to the idle control device. Furthermore, a failed performance test on an idle control device would force operators to repair, retrofit, or replace the device, increasing compliance costs with no environmental benefit because the idle device is not expected to be required for compliance. EPA recognized the environmental and cost disbenefit of testing idle emission sources in the federal standards for engines found in NSPS JJJJ[60] and MACT ZZZZ[61]. Similarly, installation of monitoring equipment on idle control devices increases costs with no environmental benefit.

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[59] 87 FR 74724

[60] §60.4244(b)

[61] §63.6620(b)

To clarify that idle control devices are exempt from performance testing and monitoring requirements, API offers the following redlines:

> *§60.5400b(a): General standards. You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas / vapor or light liquid service, and connector in gas / vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.*
>
> *§60.5401b(a): General standards. You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.*
>
> *§60.5412b: You must meet the requirements of paragraphs (a) and (b) of this section for each control device ~~used to comply~~ operated for the purpose of complying with the emissions standards for your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.*
>
> *§60.5412b(a): Each control device ~~used to meet~~ operated for the purpose of complying with the emissions reduction standard in §60.5377b(b) for your well affected facility, §60.5380b(a)(1) for your centrifugal compressor affected facility; §60.5395b(a)(2) for your storage vessel affected facility; §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska; or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (a)(3) of this section. As an alternative to paragraphs (a)(1) through (a)(3) of this section, you may install a control device model tested under*

> *§60.5413b(d), which meets the criteria in §60.5413b(d)(11) and which meets the initial and continuous compliance requirements in §60.5413b(e).*
>
> *§60.5412b(b)(1): You must operate each control device ~~used to comply~~ operated for the purpose of complying with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*
>
> *§60.5417b: You must meet the requirements of this section to demonstrate continuous compliance for each control device ~~used to meet~~ operated for the purpose of complying with emission standards for your well, centrifugal compressor, pneumatic controller, storage vessel, and process unit equipment affected facilities.*
>
> *§60.5417b(a): For each control device ~~used to comply~~ operated for the purpose of complying with the emission reduction standard in §60.5377b(b) for well affected facilities, §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section.*

5.13 The monitoring plan for control devices does not need to be site-specific.

EPA is proposing that each control device have a site-specific monitoring plan to address the monitoring system design, data collection, and quality assurance / quality control elements. Operators may install the same control device and associated monitoring system across sites in one or more company-defined areas. Similar to the fugitive monitoring plan requirement, EPA should allow monitoring plans for control devices to be based on a company-defined area or a company-wide plan for a specific make and model of control device. Like the fugitive monitoring techniques, control device monitoring is based on the type of control device and monitoring system rather than the site itself. Requiring practically identical site-specific monitoring plans for the large number of control devices increases the administrative burden for operators with no environmental benefit.

5.14 The first repair attempt timeline for covers and closed vent systems may be impractical for certain locations.

While EPA has retained the existing NSPS OOOOa requirements[62] for a first repair attempt on leaks detected from covers or closed vent systems, the 5-day timeline will apply to significantly more sites under NSPS OOOOb and EG OOOOc than NSPS OOOO and OOOOa. This requirement may be impractical for some sites that have access limitations such as those on leased farmland. While API recognizes the historic importance and priority of repairing leaks on covers and closed vent systems, a longer timeline, such as 15 or 30 days, may be more pragmatic since the number of regulated covers and closed vent systems will increase significantly under NSPS OOOOb and EG OOOOc requirements. A different first repair attempt timeline could have the added benefit of

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[62] §60.5416a(b)(9) and §60.5416a(c)(4)

making repair timelines consistent between fugitive emissions components and covers and closed vent systems, thus streamlining compliance for operators.

6.0 Storage Vessels

API supports EPA's proposed 6 tpy VOC and 20 tpy methane thresholds for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. We also support EPA's retention of the current alternate control standard to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC and 14 tpy methane. With some technical clarification concerning location, API agrees with EPA's proposed definition for a tank battery.

However, API has concerns regarding EPA's proposed criteria for legally and practically enforceable limits, the proposed definition of modification, and some of the proposed operational requirements. These items are detailed in the following section.

6.1 EPA's proposed criteria for legally and practicably enforceable limits have legal implications beyond this rulemaking and pose permitting challenges.

EPA's proposed requirements for legally and practicably enforceable limits also have legal implications beyond this rulemaking, and these restrictions violate the concept of cooperative federalism. EPA's proposed revisions are wholly inconsistent with EPA's reliance on states to administer the Clean Air Act with regard to Title V and PSD. That is, EPA allows states to establish emission limits on sites that keep sites below Title V and PSD permitting thresholds. EPA should continue to defer to states to determine the appropriate level of monitoring, recordkeeping, and reporting requirements to include in permits rather than imposing a list of strict criteria. This has long been an effective approach to reduce recordkeeping burden while reducing potential emissions.

Just as important as the legal implications discussed in Comment 12.10, the proposed criteria for legally and practicably enforceable limits provide no additional benefit and pose several permitting challenges. Existing permits and associated state programs and rules likely do not meet all the required criteria since EPA has historically deferred to the states on the sufficient monitoring, recordkeeping, and reporting requirements to include in the various levels of permits. For example, permits have proposed annual or rolling 12-month limits on emissions and production since the tank PTE thresholds and NSR permitting thresholds are based on annual emissions. EPA should clarify that such annual limits meet the proposed 30-day averaging time for production limits especially since facilities are typically permitted for a worst-case scenario. Another criterion likely not in existing permits is "*periodic reporting that demonstrates continuous compliance*". Historically, periodic reporting has applied to major sources under Title V and affected facilities regulated under a NSPS or National Emission Standards for Hazardous Air Pollutants (NESHAP), which is a small fraction of the sites that will be regulated under NSPS OOOOb and EG OOOOc. Monitoring, recordkeeping, and reporting requirements in a permit should be tailored to align with the level of authorization with minor sources having less requirements than major sources. For streamlined permitting mechanisms, such as Permits by Rule in Texas, the state agency would have to engage in rulemaking before operators could rely on such permits for determining storage vessel and tank battery PTE. Such rulemaking could take months to years, meaning that operators cannot rely on legally and practicably enforceable limits until those rule updates are finalized and effective.

The second permitting challenge is the methane emissions threshold. For permitting, methane is typically regulated as a greenhouse gas for major sources under the PSD program. States may not be able to permit a methane limit under their minor NSR programs. As such, EPA should clarify that a methane emission limit is not required to be explicitly listed in the permit provided the control device and/or production limits are included that would limit the PTE from a storage vessel or tank battery to less than 20 tpy of methane. Another approach is to allow a VOC limit of less than 6 tpy to serve as a surrogate for the methane emission limit. A potential consequence of requiring an explicit methane emission limit is that existing tanks may have a permit that does not make them an affected facility under NSPS OOOO or NSPS OOOOa but will not be able to obtain an updated permit for the purposes of EG OOOOc applicability.

Assuming operators can obtain permits that meet the proposed legally and practicably enforceable criteria, the permitting effort for the hundreds of thousands of existing storage vessel designated facilities potentially subject to EG OOOOc will take years and be an administrative burden on operators and the state permitting authorities with no environmental benefit. One member has estimated that it will take ten (10) years to obtain updated permits at the current preparation and agency review timelines. This estimated effort will likely take longer as other operators also seek to update permits at the same time. Given the potential enormous re-permitting burden for existing storage vessels/tank batteries, EPA should allow operators to rely on VOC limits as a surrogate for methane in existing permits that have previously been understood to be legally and practicably enforceable.

Overall, EPA's proposed requirements for legally and practicably enforceable limits have broad legal implications and impose real permitting challenges. The combined effect is contrary to the historical intent under NSPS OOOO and NSPS OOOOa, which is to lessen the administrative burden while still achieving the desired environmental benefits. API believes that improving the clarity of the storage vessel applicability criteria is a worthwhile effort and offers the following redline for §60.5365b(e)(2)(i):

> *For purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit ~~must~~ may include the elements such as those provided in paragraphs (e)(2)(i)(A) through (F) of this section.*

6.2 The proposed requirements for a modification and reconstruction of a tank battery require additional technical clarifications.

EPA's proposed definitions of reconstruction or modification for a tank battery require several clarifications. First, the proposed definition for reconstruction is internally inconsistent. For a tank battery consisting of more than one storage vessel, reconstruction is based on replacing at least half of the storage vessels based on the assumption that "*the cost of replacing storage vessel components such as thief hatches and pressure relief devices, in comparison to the cost of constructing an entirely new storage vessel affected facility, will not exceed 50 percent of the cost of constructing a comparable new storage vessel affected facility.*"[63] However, for a tank battery consisting of a single storage vessel, the existing provisions of §60.15 apply on the chance that the cost of replacement storage vessel components could be 50% or more of the cost to construction a comparable new storage vessel. Either the cost depreciable components on a storage vessel other than the tank itself could be 50% or more of the cost of a new comparable tank or not. Practically, this inconsistency means that operators would have to track the cost of storage vessel component replacements for single storage vessel tank batteries, but not for multi-vessel tank batteries. For both single and multi-vessel tank batteries, operators should have the option

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[63] 87 FR 74801-74802

to track either storage vessel replacements or all depreciable components. Based on this recommendation, API offers the following redline of §60.5365b(e)(3)(i):

> *"Reconstruction" of a tank battery occurs when the provisions of §60.15 are met for the existing tank battery ~~any of the actions in paragraphs (e)(3)(i)(A) or (B) of this section~~ and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section. As an alternative to the provisions of §60.15, an operator may determine reconstruction has occurred if at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> *~~(A) The provisions of §60.15 are met for the existing tank battery ; as an alternative to the provisions of §60.15, At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or~~*
>
> *~~(B) The provisions of §60.15 are met for the existing tank battery that consists of a single storage vessel.~~*

Secondly, EPA's proposed definition of modification requires clarification. API supports the first two proposed criteria for modification found in §60.5365b(e)(3)(ii)(A) and (B): "*A storage vessel is added to an existing tank battery*" and "*One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases*". Both these changes require capital expenditure on the potential affected facility (i.e., the tank battery) and would increase emissions. However, the proposed criteria in §60.5365b(e)(3)(ii)(C) and (D) regarding increases in liquid throughput are too broad and is inconsistent with §60.14(e)(2). Per 40 CFR 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification. EPA has not fully explained why it is proposing to deviate from the historical legal understanding of modification which requires both an increase in throughput and a capital expenditure on the storage vessel or tank battery. Also, increases in liquid throughput at well sites, central production facilities, and compressor stations are difficult to track as sites typically track liquid throughput using tank gauging rather than flow meters. Due to the historic understanding of modification and practical challenges of tracking liquid throughput, **API believes that §60.5365b(e)(3)(ii)(C) and (D) should be removed from the definition of modification**. [64]

However, if EPA decides to include increases in liquid throughput as a criterion for modification, API offers the following recommendations:

- **The increase in liquid throughput must also be accompanied by a capital expenditure on the tank battery itself.** Actions, such as drilling a new well or fracturing or refracturing an existing well, could increase liquid throughput and require capital expenditure but not necessarily on the tank battery itself.

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[64] Please see Section 11.6 of our comments on the original proposal for overarching legal comments on the proposed modification definitions. We note that EPA appears to have responded in part to these comments by providing that a modification to a tank battery occurs only when specified actions "result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii)" (the PTE-based applicability thresholds for storage vessels). But we note that EPA's proposed PTE criteria apply to an annual PTE and not, as specified in § 60.14, a short-term measure of PTE (such as lb/hr). This is a significant change in how a potential emissions increase should be considered in determining the existence of a modification because the annual PTE basis in practice likely results in a more expansive modification definition because the short term PTE of storage vessels in almost all cases will be much higher than an annual value, which means that more variation in actual short term emissions can be accommodated without triggering a modification than under an annual metric. EPA fails to explain why it has shifted from a short-term to an annual basis for determining emissions increases associated with a change. As a result, we do not have a reasonable opportunity to understand EPA's rationale and to provide meaningful comments.

These actions would not be considered modifications to the tank battery unless there is capital expenditure on the tank battery itself. This recommendation would make NSPS OOOOb consistent with NSPS A.

- **Reference to process unit in §60.5365(e)(ii)(C) should be removed since process unit is defined such that they should not exist at well sites and centralized production facilities.** Process unit is a term specific to natural gas processing plants and does not apply to well sites and centralized production facilities.

- **Well sites and centralized production facilities should also be allowed to compare liquid throughputs to limits in a legally and practicably enforceable permit like compressor stations and natural gas processing plants.** EPA should be consistent and allow well sites and centralized production facilities to compare liquid throughputs to limits in a legally and practicably and enforceable permit since such a permit can be relied upon for the PTE determination for all sites. **In the absence of a legally and practicably enforceable limit, all sites should be allowed to compare liquid throughputs to those used to design the existing cover and closed vent system in operation when a potential modification action occurs.** These recommendations would also make modification criteria consistent for all sites and clearly define what an increase in liquid throughput is.

Based on these recommendations, API offers the following redlines to §60.5365b(e)(3)(ii):

> *“Modification” of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through ~~(D)~~(C) of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> *(A) A storage vessel is added to an existing tank battery;*
>
> *(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; or*
>
> ~~*(C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well).*~~
>
> *~~(D)~~(C) ~~For tank batteries at compressor stations or onshore natural gas processing plants,~~ A capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or ~~(D)~~(C) of this section) determination of the potential for VOC or methane emissions; or in the absence of a legally and practicably enforceable permit, a capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or (C) of this section) design of the storage vessel cover(s) and closed vent system.*

6.3 Additional technical clarifications to proposed definitions are warranted to clarify applicability of certain requirements for tank batteries.

Since the proposed requirements for NSPS OOOOb and EG OOOOc will apply for the tank battery, there are additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria. We support EPA's proposed definition for tank battery based on storage vessels that are manifolded together for liquid transfer, but offer a minor clarification on respect to its location as follows:

> *Tank battery means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant if only one storage vessel is present.*

This clarification addresses the situation of a single storage vessel not located at a well site, central production facility, compressor station, or natural gas processing plant (e.g., drip station along a pipeline). These storage vessels typically have low throughput and methane and VOC emissions. In §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii), EPA does not describe how to determine PTE for tank batteries at location other than a well site, centralized production facility, compressor station, or natural gas processing plant. Therefore, API believes that the agency did not intend to regulate these low-emitting tanks with these proposed rules.

6.3.1 The definition of compressor station must be clarified with respect to the storage vessel applicability provisions in §60.5365b(e).

With the introduction of the newly defined central production facility, an additional clarification is needed for when and how to calculate the tank battery PTE at well sites and central production facilities that may have compression versus at a compressor station. The EPA makes this distinction clearly for how to consider the fugitive emission monitoring by referencing §60.5397b in the definition of compressor station. As an example, consider a reciprocating compressor at an oil processing facility. The facility would be a "*tank battery at a well site or centralized production facility*" under §60.5365b(e)(2)(ii) and yet also a "*tank battery located at a compressor station*" as used in §60.5365b(e)(2)(iii).

We therefore request EPA also clarify the storage vessel requirements in a similar way by referencing of §60.5365b(e) in the definition of compressor station as follows:

> *Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of §60.5365b(e) and §60.5397b.*

In terms of the PTE calculations, centralized production facilities should be considered like compressor stations and natural gas process plants because the storage capacity is typically based on "a projected maximum average daily throughput". Therefore, API offers the suggested redlines for §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii).

> *(ii) For each tank battery located at a well site ~~or centralized production facility~~, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided*

in paragraph (e)(5)(iv) of this section. The potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

(iii) For each tank battery located at a centralized production facility, compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station or onshore natural gas processing plant or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.

Another suggested solution is to harmonize the PTE calculation requirements for all sites based on the requirements proposed for compressor stations and gas plants.

6.3.2 A storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant used to alleviate dangerous, or emergency events must be clearly excluded from the definition of storage vessel.

At some facilities, storage vessels may be installed for the sole purpose of providing relief from pressure vessels during emergencies. Previously, these storage vessels would not trigger applicability as a single emergency use vessel was unlikely to exceed 6 tpy VOC threshold under NSPS OOOO or NSPS OOOOa. These tanks now present a challenge with the new applicability threshold proposed in NSPS OOOOb and EG OOOOc for the tank battery. At the state level, emergency use tanks are exempt from control requirements from states and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.[65,66] We request EPA provide an exclusion for emergency use tanks from the definition of storage vessel as follows:

> *Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:*
>
> - *Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180*

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[65] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[66] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

- *Process vessels such as surge control vessels, bottoms receivers or knockout vessels.*
- *Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.*
- *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

6.3.3 EPA should clarify that location is not a restriction on the use of a floating roof tank.

In §60.5395b(b)(2), EPA correctly prohibits the use of a floating roof if the storage vessel or tank battery has flashing emissions. However, EPA also prohibits the use a floating roof at a well site or centralized production facility. Flashing emissions alone, regardless of location, should prohibit the use of a floating roof tank because flashing emissions, not location, could prevent proper operation of a floating roof.

API offers a recommended redline in Comment 6.5.

6.4 The requirement to manifold the vapor space of each storage vessel in the tank battery is overly prescriptive and unnecessary.

As part of the control requirements for storage vessel affected facility, EPA proposes that "*The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery*"[67]. This requirement to manifold the vapor space of each storage vessel in a tank battery is unnecessary and restricts an operator's flexibility in achieving compliance with the required 95% emissions reduction. An operator should be able to install any number of control devices and manifold the vapor space of the storage vessels from one or more tank batteries into one or more closed vent systems so that each control device is properly sized for the expected vent gas flow rate.[68] The requirement to manifold the vapor space of a tank battery may also cause confusion with the proposed definition of tank battery which is based on storage vessels manifolded together for liquid transfer.

API offers a recommended redline in Comment 6.5.

6.5 EPA should provide an exemption from control requirements due to technical infeasibility if the control device or VRU would require supplemental fuel.

With the change in affected facility from a single storage vessel to a tank battery, control devices will be required for a longer time compared to NSPS OOOO and NSPS OOOOa – until the actual uncontrolled emissions from the tank battery (versus each individual storage vessel) are below 4 tpy VOC and 14 tpy of methane. This longer

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[67] §60.5395b(b)(1)(ii)

[68] If not corrected, EPA's failure to consider these obvious and important aspects of its proposed manifolding requirement would render such a requirement arbitrary and capricious. Motor Vehicle Mfrs. Assn. v. State Farm Mut. Automobile Ins. Co., 463 U.S. 29, 43 (1983).

period for the control requirement will increase the likelihood that some control devices or VRUs will require supplemental fuel to be technically feasible. As discussed in Comment 5.6.3 for control device pilot flames, operators may have to bring propane for supplemental fuel for sites without fuel gas or burn additional sour fuel gas. As such, API recommends EPA consider an exemption from control requirements for a tank battery if use of a control device or VRU would be technically infeasible without supplemental fuel for pilot flame or other purposes. Such exemptions currently existing in state regulations for storage vessels and tank batteries including Colorado. Based on the language for the Colorado exemption, API offers the following recommended redlines to the control requirements in §60.5395b(b), which also includes the previous comment:

Control requirements.

(1) Except as required in paragraphs (b)(2) and (b)(3) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through ~~(iv)~~ (iii) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);

~~*(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;*~~

~~(iii)~~(ii) The tank battery must be equipped with ~~a~~ one or more closed vent systems that meet~~s~~ the requirements of §60.5411b(a) and (c); and

~~(iv)~~(iii) The vapors collected in paragraph~~s~~ (b)(1)(ii) ~~and (iii)~~ of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) For storage vessel affected facilities that do not have flashing emissions ~~and that are not located at well sites or centralized production facilities~~, you may use a floating roof to reduce emissions. If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb. You must submit a statement that you are complying with §60.112b(a)(1) or (2) with the initial annual report specified in §60.5420b(b)(1) and (8).

(3) You may apply to the Administrator for an exemption from the control requirements in paragraphs (b)(1) of this section if the use of a control device would be technically infeasible without supplemental fuel. Such request must include documentation demonstrating the infeasibility of the control device.

7.0 Natural Gas-Driven Pneumatic Controllers

Pneumatic controllers play a pivotal role in the safe operations at oil and natural gas facilities – including at well sites, central productions facilities, compressor stations, and processing plants. In our review of the proposed requirements EPA has not adequately addressed some of the major concerns we identified in our January 31, 2022 comment letter.[69] EPA has severely overstated the deployment capabilities for solar installations to power oil and gas infrastructure in support of their proposal, which indicates a continued lack of understanding of how pneumatic controllers (and pneumatic pumps) would be converted to achieve a non-emitting standard.

For NSPS OOOOb, we support the use of non-emitting pneumatic controllers, contingent on clarifications as described herein, for newly constructed, modified or reconstructed well sites, central production facilities, and compressor stations. We also support EPA excluding emergency shutdown devices from these provisions as it allows for safety in case of emergency.

For existing natural gas-driven pneumatic controllers under NSPS OOOOc, we continue to maintain that 1) adequate time and phase-in must be provided to properly account for the magnitude and scale of sites converting to non-emitting controllers and 2) it is most appropriate to focus conversion to non-emitting controllers at facilities with the largest number of controllers (see Comment 7.5). To effectively do this, the use of low continuous bleed or intermittent natural gas-driven pneumatic controllers should be allowed and should be monitored periodically for proper functioning at the frequency specified in §60.5397c. An initial analysis[70] of the potential impact of the rule should it require conversion to non-emitting pneumatic controllers at all existing facilities shows that it could result in the premature shut-in of a significant percentage of existing wells, particularly when considered in context with the proposed monitoring requirements[71]. EPA should allow additional flexibility in this area as we have described to allow states to preserve the remaining useful life of facilities.

7.1 Adequate implementation time must be provided for pneumatic controller and pneumatic pump requirements under both NSPS OOOOb and EG OOOOc.

As we have stated earlier, adequate time is required to implement the proposed control standards as they fundamentally shift how pneumatic controllers and pneumatic pumps have typically been operated. While new surface locations can typically plan for controls during site design, the supply chain delays pose a genuine and significant concern for all aspects of implementing the pneumatic controller requirements. Anecdotal evidence from one operator that is currently conducting retrofits in New Mexico has identified that air compression equipment is in short supply with around 8 months of delays and another operator that has been piloting solar panel instrument air systems is now experiencing delays of 18 to 24 months on previously made orders. While eventually the market will rise to meet this demand, that market correction has not yet been realized and presents very real concerns for our members. Currently there are hundreds of operators attempting to order equipment for thousands of sites. While we are generally supportive of the proposed requirements (with the necessary and specific clarifications that we have requested), the current proposed timeline for compliance is unrealistic due to global circumstances beyond any operator's ability to control or influence.

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[69] EPA-HQ-OAR-2021-0317-0808

[70] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API's request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

[71] See Comment 2.0

As anecdotal evidence, our members operating in New Mexico are currently working through retrofits of facilities in compliance with state regulations. Instrument air systems are currently on backorder with a wait time of approximately 8 months. This wait time is expected to be exacerbated when EPA's final rule takes effect. Once equipment is received, only 1-3 facilities can be retrofit per operator per week based on type or size of the facility, weather conditions, etc. This means for any given operator, only approximately 50-150 retrofits can successfully take place in a single year. For operators with thousands of new, modified and existing locations, the current proposed timelines are untenable.

Based on EPA's proposed November 2021 applicability date, there are thousands of sites that may now require retrofit under NSPS OOOOb. Since operators are currently experiencing 6-to-8-month delays in acquiring the necessary control equipment for instrument air system conversions, we suggest EPA amend the requirements to reference "upon receipt of equipment" similar to how certain delay of repair provisions have been framed within other regulations.

For pneumatic controllers and pumps under EG OOOOc, given all of the existing sites in the U.S. and the implementation aspects outlined above, we continue to have serious concerns that 5 years for conducting retrofits of this magnitude would not provide adequate time given current and anticipated supply chain delays. Because of these constraints for EG OOOOc, EPA should consider a longer phase-in period where facilities with the largest number of controllers are retrofit first.

7.2 For NSPS OOOOb and EG OOOOc, EPA should allow the routing of emissions from natural gas-driven controllers to a control device.

We continue to suport the routing of certain controller emissions to a flare or other combustion device. In its analysis, EPA dismisses this option by finding that routing pneumatic controller vent gas to a process is cost-effective and thus BSER; however, EPA's analysis fails to account for the cost-effectiveness of the incremental 5% of methane and VOC emissions reductions achieved when comparing routing to process against routing to a control device, which conservatively assumes a control device will achieve only 95% reduction.[72] In many cases, the actual performance of a control device exceeds 98% control. Instead, EPA's analysis focuses on the cost-effectiveness of no control against 100% control. API requests that EPA include routing to a control device as a compliance standard under NSPS OOOOb and EG OOOOc. If EPA does not adopt routing to a control device as an emissions reduction standard, it must demonstrate as cost-effective the incremental 5% of emissions reductions achieved through routing to a process or converting to instrument air.[73]

As an example, one facility may choose to install an instrument air system to convert most natural gas-driven pneumatic controllers on site, but emissions from certain types of controllers that are associated with the flare system itself (e.g. back pressure valve[74]) could more easily route emissions to the flare header. By EPA not allowing for this site configuration, some operators may need to reconfigure controllers that are currently already

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[72] 87 Fed. Reg. at 74765-66.

[73] As further support for the above, API responds to EPA's request for information regarding whether vapor recovery units (VRU) are ever necessary to route pneumatic controller vent gas to a process. While it is feasible for operators to route pneumatic controller vents to a downstream process that operates at a lower pressure, a VRU is necessary if no such lower-pressure destination exists or is of limited availability. Installation of a VRU is capital intensive, and VRU maintenance is costly and challenging, especially in extreme weather climates. Where downstream process pressure exceeds vent gas pressure, the pneumatic controller vent gas cannot feasibly route to a downstream process without compression. If EPA is unwilling to allow routing of pneumatic controller vent gas to a control device as an emissions reduction standard on the same footing as routing to a process, EPA should allow routing to a control device where routing to a process is infeasible (taking into account technical and economic considerations), and define infeasibility to include scenarios where routing to a process requires a VRU.

[74] Back pressure valves can be routed to the flare when they are in close proximity to the flare header since they only actuate when there is an over pressurization.

routed to a flare or other combustion device. In this scenario, VOC and methane emissions from these routed controllers are already reduced by 95% or more. EPA has provided no basis for not authorizing routing to control as an option.

Adopting this methodology as a compliance standard can be achieved by amending the proposed definition of "self-contained pneumatic device" to include natural gas-driven controllers routed to control devices in that definition (refer also to Comment 7.3). Such a revision is consistent with both New Mexico and Colorado's regulations – which define non-emitting to include pneumatics routed to combustion.

7.3 Additional technical clarifications are warranted to clarify applicability of certain natural gas-driven pneumatic controller requirements.

While we support inclusion of flexible solutions to reduce emissions from natural gas-driven pneumatic controllers, we have identified critical aspects of the proposed provisions that require technical clarification or simplification as we have outlined herein.

7.3.1 Suggested clarifications to certain proposed definitions related to pneumatic controllers in NSPS OOOOb and EG OOOOc.

There are some additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria as proposed. There are many types of automated instruments that maintain a process condition that are not pneumatic controllers. Many of the proposed definitions must clearly identify pneumatic controllers from these other instruments and be more specific to avoid confusion.

> ***Bleed rate*** *means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a fixed orifice in a pneumatic controller.*
>
> ***Continuous bleed*** *means a natural gas-driven pneumatic controller that is designed with a continuous flow of ~~pneumatic supply~~ natural gas from ~~to~~ a fixed orifice~~ pneumatic controller~~.*
>
> ***Non-natural gas-driven pneumatic controller*** *means an automated process control device that utilizes instrument air or hydraulic fluid as the motive force to change valve position. ~~Instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.~~*
>
> ***Pneumatic controller*** *means an automated instrument that manipulates a valve's position with pressurized gas to ~~used for~~ maintain~~ing~~ a process condition such as liquid level, pressure, delta-pressure and temperature.*
>
> ***Self-contained pneumatic controller*** *means a natural gas-driven pneumatic controller in which the motive gas is not vented to the atmosphere but captured ~~releases gas~~ into ~~the~~ downstream piping for process use, sales or control such that there are no direct methane or VOC emissions from the controller.~~, resulting in zero methane and VOC emissions~~*

7.3.2 EPA must clarify the pneumatic controller requirements in NSPS OOOOb and EG OOOOc apply after startup of production and to stationary equipment only.

We agree with EPA'a assertion in the preamble where (87 FR 74759) *"The EPA acknowledges that the focus of the BSER analysis has been on stationary sources and pneumatic controllers that are part of the routine operation of oil and natural gas facilities."* The zero-emissions requirements are not justified for short term controller usage related to non-stationary sources.[75] Retrofitting controllers located on temporary equipment requires significant engineering design that has not been adequately evaluated to identify if these options are even possible, nor technically achievable nor practically attainable. Pneumatic controllers located on temporary or portable equipment should be allowed to operate as low-bleed or intermittent as needed for proper functioning of the temporary equipment. Some examples of temporary equipment or activities that should be excluded from the proposed provisions include the following:

- **Temporary Equipment (such as compressors):** Operators may utilize a small injection compressor to assist in ramping up production for new wells that have recently ended flowback. These compressors are typically skid mounted and located on site for as few as 30 days after the startup of production. These compressors contain a handful of pneumatic controllers to assist in proper function on the unit and may sometimes be leased from a third party. Another example is the use of a temporary compressor at a wellsite that is needed in anticipating gathering system high line pressure during new gathering system infrastructure build-out, which may occur for a few months. We ask that EPA exclude any natural gas-driven pneumatic controllers on equipment that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 180 consecutive days. This approach is consistent with language describing applicability of temporary storage vessels under NSPS OOOO, NSPS OOOOa, proposed NSPS OOOOb, and proposed EG OOOOc.

- **Drilling and Completion Activities:** As EPA is aware, drilling and completion activities require specialized temporary use equipment that is often contracted by third-party operators. Any pneumatic controllers associated with drilling and completion equipment should be excluded from the zero-emitting controller requirements, which can be accomplished by clarifying that the requirements for pneumatic controllers are not applicable until after the startup of production like other provisions within the proposed standards.

7.3.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic controllers.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms 'natural gas-driven pneumatic controller' and 'pneumatic controller' interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic controllers. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric controllers at the well site as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(d)(1):

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[75] Exemption of controllers on temporary equipment is consistent with state regulations in New Mexico and Colorado.

> *For the purposes of §60.5390b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more.*

We offer a suggested redline for reconstruction below in Comment 7.3.4.

To be clear, our support for the proposed provision as it relates to modification for natural gas-driven pneumatic controllers is contingent on this and the other clarifications requested throughout Comment 7.3. Absent these clarifications then we maintain our previous position submitted in our January 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) and request EPA streamline applicability across various affected facilities by defining modification for the collection of natural gas-driven pneumatic controllers and pneumatic pumps like how EPA has defined modification for the collection of fugitive components at well sites and compressor stations. For central production facilities, modification should be based on an increase in designed throughput capacity with the addition of a storage vessel at the central production facility as we further elaborate in Comment 2.6.

7.3.4 Under NSPS OOOOb, reconstruction for natural gas-driven pneumatic controllers should not include replacement of a high-bleed natural gas-driven controller with a low-bleed or intermittent controller.

Many of our members have committed to the elimination of all remaining high-bleed controllers that may still be in use at existing locations. As we included in our January 31, 2022 comment based on data submitted to EPA through EPA's Greenhouse Gas Mandatory Reporting Program, data extracted for the 2020 calendar year clearly shows the breakdown of high-bleed natural gas-driven pneumatic controllers is only around 2% of total reported natural gas-driven pneumatic controllers across both the onshore production segment and onshore gathering and boosting segments. This indicates there are not many high-bleed devices left in operation at well sites, central production facilities, and compressor stations based on successful implementation of NSPS OOOO and NSPS OOOOa over the last decade.

Replacement of these last remaining high-bleed controllers with low-bleed or intermittent controllers would equate to an overall reduction in methane and VOC emissions and should not be included in the reconstruction provisions as this could disincentivize short term benefits of this type of replacement. With the implementation of EG OOOOc coinciding with proposed NSPS OOOOb, this clarification will only delay conversion to non-emitting without impacting current investment in equipment upgrades in the near term that provide immediate environmental benefit.

We offer the following suggested redline to §60.5365b(d)(2) to address these concerns and the clarification explained in Comment 7.3.3:

> *§60.5365b(d)(2): For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of existing natural gas-driven pneumatic controllers at the site in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic controllers is replaced. That is, if*

an owner or operator meets the definition of reconstruction through the "number of controllers" criterion in (d)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of natural gas-driven pneumatic controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic controller replacement. Replacement of an individual natural gas-driven controller with a continuous bleed rate greater than 6 scfh with either a natural gas-driven controller with a continuous bleed rate less than 6 scfh or with an intermittent vent natural gas-driven pneumatic controller is excluded from this determination.

If the owner or operator applies the definition of reconstruction in §60.15(b)(1), reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven pneumatic controllers at the site. The "fixed capital cost of the new pneumatic controllers" includes the fixed capital cost of all natural gas-driven pneumatic controllers which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic controllers that are replaced, the owner or operator must also comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review.

7.3.5 Additional clarifications are required to the proposed requirements for reconstruction of pneumatic controllers.

In review of the proposed regulatory text provided for §60.5365b(d)(2), the following are elements of the proposed regulatory text require clarification.

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed in §60.5365b(d)(2).** The proposed language in §60.5365b(d)(2)(ii), suggests that reconstructed natural gas-driven pneumatic controllers would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic controllers. We believe it was EPA's intent to

not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 Supplemental Proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 Supplemental Proposal.

7.4 Self-contained natural gas-driven controllers should follow the requirements for fugitive emission monitoring, not those for closed vent systems.

Self-contained natural gas-driven pneumatic controllers are configured to route emissions into the downstream piping, which is simply a hard piece of pipe with connectors or flanges. Given the simplicity and low potential for leaks or defects along the piping, EPA is correct in allowing OGI inspections, but we believe operators should follow the work practice for the fugitive emission monitoring requirements §60.5397b and not the NIE provisions as proposed.[76] EPA should also allow inspection of self-contained pneumatic controllers via the alternative screening techniques program, when applicable.

We also note that as proposed, the self-contained pneumatic controller requirements do not articulate repair or contain delay of repair provisions or timelines and we believe this was not EPA's intent. Given self-contained pneumatic controllers would more commonly occur on pressure control valves, the operator would likely need to shut-in the well or shutdown equipment in order to conduct any sort of repair (if any were found). We therefore request, at a minimum, that repair timelines in §60.5397b(h) and specifically the delay of repair provisions as described in §60.5397b(h)(3) apply to self-contained natural gas-driven pneumatic controllers.

As we mention in Comment 2.4, we encourage EPA to streamline how periodic monitoring in the proposed rules is conducted by following a consistent set of requirements including the frequency, repair schedule, and retention of associated records. This will provide clarity across all affected facilities at a site where monitoring is occurring.

7.5 For EG OOOOc, locations without access to electrical power should have the option to use low continuous bleed or intermittent bleed natural gas-driven pneumatic controllers with proper functioning confirmed through periodic monitoring until modification or reconstruction triggers NSPS OOOOb. At a minimum, EPA must consider an allowance for low production well sites and/or sites with a limited number of natural gas-driven controllers from retrofit within EG OOOOc.

Many existing well sites are low producing wells that could be close to end-of-life of their production cycle and may only contain a limited number of controllers. The complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production versus implementation of the collective costs associated with EG OOOOc. The BLM acknowledged this fact in their proposed Waste Prevention Rule by establishing an exemption of retrofit of pneumatic controllers based on facilities *"producing at least 120 Mcf of gas or 20 barrels of oil per month"* because *"it is unlikely that an*

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[76] Should EPA continue to apply NIE as a numerical standard for self-contained pneumatic controllers, it could disincentivize conversion.

operator of a lease, unit, or CA producing only 120 Mcf of gas or 20 barrels of oil per month could re-direct the entirety of its revenues for 10 months towards paying for upgrading its pneumatic equipment."[77]

In our previous comment letter submitted January 2022, we supported retrofit for facilities with at least 15 controllers at a well site, central production facility, or compressor station. There have not been any drastic changes in actual costs to retrofit facilities or technical feasibility of implementing these types of retrofits in locations that do not have access to grid power. In fact, due to other similar regulations currently being implemented at the state level, the timeline for acquiring the necessary equipment is long due to supply chain limitations, and skilled labor is in short supply and high demand. We maintain our position that at these existing facilities any high-bleed natural gas-driven pneumatic controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company's fugitive emission monitoring program to monitor for proper functioning. The recordkeeping and reporting for these devices should follow requirements associated with fugitives and not have a separate set of requirements as currently proposed for sites in Alaska.

7.5.1 Spacing constraints at existing sites may cause technical infeasibility for converting to non-emitting controllers where grid power is not available.

Existing well site sites, central production facilities or compressor stations may have sizing constraints for the proper placement (due to safety and other permitting constraints) of instrument air control systems. Examples include an instrument air compressor that must sit outside of classified areas, generators, and/or or solar panels.

To retrofit a facility with an instrument air system, an engineer first verifies that adequate power is available and then applies for necessary state level permits, which takes approximately 60 days to acquire (if approved). On federal lands, this type of project would require reopening permits pursuant to National Environmental Policy Act, which is around a 12 to 18 month permitting process. On private lands, an operator may not be able to purchase additional land from the private owner.

During construction, an instrument air header and compressor skid must be added to the facility. The air compressors must sit outside of classified areas and therefore, some older reclaimed facilities may not have adequate space to add necessary equipment for the instrument air system because the air compressor must be placed outside of a safe radius from existing flares and other hydrocarbon-containing equipment (e.g. limitations due to electrical classifications). If accessible grid power is not available, a generator would have to be installed to power the air compressor, which would emit other pollutants.

7.5.2 Case Study Review for Land Required for Solar Retrofits

For existing medium and larger production sites and tank batteries, larger solar installations will be required to transition the sites to the proposed zero-emitting standard. As a case study, multiple sample sites throughout the country were evaluated to determine the space requirement for a solar installation that is equivalent to the energy of an instrument air system requiring 112 kilowatts (kW), which would be needed for large facilities not included in EPA's model plant analysis. Results are presented in Table 1.

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[77] 87 FR 73606

This case study highlights that the land requirement for many sites is likely to be between 0.6 – 1.5 acres. Several key considerations to consider when installing solar panels at existing well sites that hinder the compatibility include:

- Site area footprints have already been agreed to and installing large arrays will require revisiting existing agreements to modify, a time consuming and costly process. Many jurisdictions, including the BLM, prefer smaller facility footprints.
- Site layout is already optimized for existing infrastructure to fit within a facility area.
- Adding in solar infrastructure of panels, wiring, battery, etc. could lead to complications and unnecessary safety hazards as batteries are introduced near hydrocarbons.
- Snowfall is prevalent in many of these regions and will reduce efficiency of the optimally angled panels. Vertically oriented arrays to prevent snowfall interference may not be appropriate in all circumstances unreasonable given the climate, wind, and remote nature of these sites.

Table 1. Case Study – Physical Land Requirement for Solar Installations Replacing Power Supply for 112 kW Generator

Site Location	Optimally Angled Panels[a]					Vertically Angled Panels[b]				
	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage[g]
	kW	degrees	Hours			kW	degrees	Hours		
Carlsbad, New Mexico	620	28	5.1	2,067	0.7	1513	90	2.1	5,044	0.9
Midland, Texas	620	28	5.1	2,067	0.7	1558	90	2.0	5,193	0.9
Arnett, Oklahoma	735	30	4.3	2,452	0.8	1318	90	2.4	4,392	0.8
Denver, Colorado	719	31	4.4	2,396	0.8	1171	90	2.7	3,904	0.7
Pinedale, Wyoming	988	33	3.2	3,294	1.1	1091	90	2.9	3,635	0.6
Williston, North Dakota[h]	1318	35	2.4	4,392	1.5	1091	90	2.9	3,635	0.6

a. Optimally angled tilt (annual average) determined from National Renewable Energy Lab (NREL)’s PVWatts® Calculator; https://pvwatts.nrel.gov/pvwatts.php

b. Vertically angled systems were suggested by Clean Air Task Force at EPA-HQ-OAR-2021-0317-1451.

c. Size of installation determined from Omni calculator methodology required inputs of electricity consumption and solar hours per day to determine roof area of solar panels; https://www.omnicalculator.com/ecology/solar-panel

d. Using NREL’s PVWatts calculator in conjunction with the Omni calculator, it was determined roof area was equal to ground area for simplification as, there was a <1% difference in annual kWH production.

e. Footprint Hero was used to determine the lowest monthly average daily peak sun-hours for each location for both panels at optimal angle and 90 degrees; https://footprinthero.com/peak-sun-hours-calculator

f. Number of panels based on average panel output of 300 watts and 15 square feet.

g. Acreage for vertically angled panels assumes panels would be stacked two panels high.

h. The high latitude of Williston, North Dakota has the lowest monthly average daily peak sun-hours when the solar array is optimally positioned. When vertically positioned the peak sun hours increases from 2.4 hours to 2.9 hours.

EPA should also consider the following in conjunction with results of this analysis:

- the cost of land acquisition;

- right-of-way and easement concerns/limitations;
- projection of further land-use change requirements for solar installations; and
- percent of further land use change required for solar installations on designated wetlands.

For existing locations without accessible grid power and where there is an ability to acquire additional land to use solar or natural gas generators, operators will not have the ability comply with the current proposal.

7.5.3 The incremental costs and benefits have not been adequately justified at existing locations.

Within the technical Support documentation, EPA does include a scenario for monitoring intermittent vent controllers. Based on EPA's own assumptions, this type of program can achieve 96.7% reductions in emissions (based on emission factors) for an overall site level control efficiency of 65% based on semi-annual OGI monitoring. Since many large facilities within the proposal will be required to conduct quarterly OGI, we anticipate this control efficiency to be even higher.

Furthermore, since all well sites, central production facilities and compressor stations will already be subject to fugitive emission monitoring at some frequency, the incremental cost to implement such a program for pneumatic controllers would be solely based on the additional recordkeeping and reporting that an operator would need to implement. The incremental costs and benefits associated with the zero-emitting provisions in comparison with this option to monitor controllers for proper functioning within a company's LDAR program, have not been adequately justified given the numerous technical infeasibility challenges communicated with implementing solar-powered electric controllers, spacing constraints at some existing facilities to install certain equipment, and other emission offsets that will stem from implementing other forms of power generation.

In EPA's analysis, the emission reductions from inspections of intermittent vents are based on emission rates assumed to be halfway between perfectly operating post-inspection controllers and the overall emission rate that includes both perfectly operating and malfunctioning controllers. This suggests that EPA has no data or understanding of how often intermittent bleed devices may not function properly, which is an important distinction given the expected costs of implementing these requirements at all locations as proposed under EG OOOOc.

7.6 EPA's cost-benefit analysis significantly underestimates the costs of implementing the proposed zero-emissions standard and overestimates the technical capabilities of solar and electric controllers.

In our January 31, 2022 comment letter, we provided detailed comments on the technical challenges that operators within U.S. are facing as they convert facilities to electricity, pilot solar powered instument air systems, and install natual gas-driven instrument air systems, which we incorporate again by reference.[78] As our members begin to plan, design and install zero-emitting penumatic controllers, it is clear that EPA has not adequately accounted for the costs of this proposal; especially with respct to retrofit of existing facilities. Total project costs, including equipment and labor, to retrofit a large gathering and boosting compressor station could exceed $1,000,000, which is substantially higher than EPA's projections.

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[78] Comments found in EPA-HQ-OAR-2021-0317-0808

Upon review of the supplemental techncial Support Document, we have found EPA's cost-benefit analysis to significantly underestimate the cost (especially for retrofit of existing facilities) and overstate the techncial feasibility of making these retrofits as summarized below:

- EPA applied an emission factor for low-bleed pneumatic controllers, with a factor that by definition would be a high-bleed pneumatic controller. EPA has justified this update within the model plant by aligning the model plant to the proposed changes to Subpart W which is 6.8 scf/h. This emission factor is nearly a five-fold increase to the continuous low-bleed device emission factor; is greater than the threshold that had been applied to determine whether a device should be categorized as low-bleed or high-bleed; and a device with this level of emissions would not be allowed pursuant to NSPS OOOO or NSPS OOOOa. In our review of the proposed changes to Subpart W, we have asked EPA to provide the details of how this factor was determined as there is little documentation supporting this change. Regardless, it is an inappropriate factor for applying to a low-bleed device for NSPS OOOOb and EG OOOOc because an operator would not be able to install a continuous bleed natural gas-driven pneumatic controller with this manufacturer rating as it is considered a high-bleed pneumatic controller.
- EPA continues to describe application of solar-powered and electric controllers as being directly powered by the grid or solar technology in the model plant analysis. Operator experience is that sufficient air is required to properly control the pneumatic controllers, where an instrument air system (i.e., an air compressor and associated equipment and piping) is required in nearly all applications. Electric controllers lack the speed and performance of gas-powered or air-powered actuators and there are limited equipment configurations where electric controllers are technically feasible. Specifically, electric controllers have inadequate duty cycle ratings, and the torque ratings are typically too low for reliable performance. This significantly limits the utility of electrically actuated controllers. Even if they performed comparably to gas-powered actuators, electrically actuated controllers have a higher failure rate, especially for throttle service where the actuator is constantly adjusting based on process conditions instead of at a set point. The modelled analysis for these scenarios incorrectly estimates the cost-effectiveness of the proposed requirements.
- Application of solar technologies as it pertains to gathering and boosting compressor stations have not been adequately reviewed in EPA's model plant analysis. The production sector model plants are geared toward small well sites with only 4, 8 and 20 controllers analyzed. Larger facilities, i.e., those with more than 20 pneumatic controllers, are still not adequately accounted for.
    - The assumptions made by EPA in the model plant analysis severely underestimate the air compressor horsepower and instrument air needs for sites with more than 20 controllers. These smaller scale cost metrics will not linearly scale up with larger facilities where a new instrument air header and piping may need run across the larger Gathering & Booster station site and additional pipe supports or extended pipe rack may be necessary. In our January 31, 2022 comment letter we provided information on facilities using instrument air systems to power over 100 controllers.
- In a case study published by NREL[79], solar panel capital costs for off-grid production well sites are 2.7 times the cost of grid-connected well sites. This does not align with EPA assumptions.
- EPA's model plant assumptions do not adequately address costs associated with retrofit of existing facilities. We note that installation also necessitates the facility be temporarily shut in/shut down to

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[79] https://www.nrel.gov/docs/fy20osti/76778.pdf

perform retrofits, which does not appear to be accounted for. Additional costs for retrofit at existing facilities that are missing from EPA's analysis include:

  - Additional Land Requirement for Solar Panel Installation including acquisition costs.
  - Site Preparation – For existing sites with tree lines, trimming may be required to maximize sun exposure. Additionally, for larger sites with more significant solar installations, foundation prep including concrete slabs was not considered.
  - Solar panel maintenance and cleaning particulate accumulation.
  - Permitting[80], Insurance and inclusion of battery boxes to house batteries in cold regions do not appear to be accounted for.
  - Retrofits often require the existing methane pipe headers to remain in place as a source of fuel gas for on-site equipment (compressors, fired heaters, combustors/TO's, flares, etc.) and a new parallel air header needs to be run to a to all instruments. This can add significant costs depending on the site layout, if there is available space in the existing pipe rack and facility, or if additional pipe supports are also needed.

- While EPA recounts and summarizes the significant number of comments criticizing solar-powered controllers (87 FR 74764), the primary underlying basis to EPA's economic and technical feasibility analysis pertaining to the conversion of existing, natural gas-powered pneumatic control systems to zero-emission systems (e.g., electric, solar-powered) is based on a single report: *Zero Emission Technologies for Pneumatic Controllers in the USA initially published in August 2016 and then updated in November 2021 by Carbon Limits (on behalf of the Clean Air Task Force).*[81] The report and EPA's application of report costs within the model plant analysis have a number of flaws as we have described herein and as follows:

  - The 2021 Carbon Limits report authors primarily gathered information through interviews with three technology providers and two oil and gas companies, both production-oriented companies with limited application of the technologies. The report is based on installation of solar-powered instrument air systems at only 22 onshore production sites located in Alberta, Canada, Wyoming, Utah, and Peru. This is an extremely small sample size for a technology to be deemed technically feasible and cost effective for all U.S.-based oil and natural gas operations. In response to our comments Clean Air Task Force states "Some of the interviewed technology providers have installed these systems in over 400 well-sites." Again, this is a rather small population when considering the number of facilities that will be applicable to these rules.

  - The Carbon Limits report focuses on reliability of solar power systems in colder climates, not areas with limited sun exposure. The Canadian provinces cited in the study, Alberta and British Columbia, experience very large amounts of sunshine, supporting the idea that solar power

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[80] https://www.solarpermitfees.org/SoCalPVFeeReport.pdf

[81] This basis was explicitly stated by EPA on page 46 of 173 to document Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS), 40 CFR Part 60, subpart OOOOc (EG) (October 2022). EPA states, "The EPA notes that the primary basis for the costs used for the November 2021 analysis was not the White Paper, but rather a 2016 report by Carbon Limits, a consulting company with longstanding experience in supporting efficiency measures in the petroleum industry.The analysis was updated to reflect the information in the 2022 Carbon Limits report."

generation works best in areas with more sun. The study does not support reliability of solar powered systems in areas of limited sun exposure like West Virginia.

- Identified calculation errors and assumptions in the model plant analysis:
  - The EPA cost analysis appears to contain a calculation error in determining the annualized project cost; while a solar panel lifespan of 10 years was stated, a value of 15 years was used in the annualization, resulting in a 30% annual cost difference. See tabs in Supplemental TSD Ch 3 Pneumatic Controllers.xlsx tabs *BSER T&S new, BSER T&S existing, BSER Production new, and BSER Production existing.*
  - The EPA capital cost analysis for electric compressor retrofit at existing transmission, storage, and production sites does not consider applications greater than 10 hp (highest compressor and associated equipment (e.g., dryers, wet air receivers) is capped at $32,000). Larger-sized systems should be evaluated.
  - For electric powered compressed air systems, EPA applied an annualization period of 15 years. If the compressor equipment life is updated to reflect the 2021 Carbon Limits Study provided value of 6 years, this option is not economically feasible. It is unclear why EPA deviated from the Carbon Limits study for this assumption and not others.
  - Carbon Limits updated certain assumptions in the 2021 report release. For some assumptions, EPA continues to retain costs from the 2016 study, without explanation.
  - The Carbon Limits report assumed a greenfield installation factor of 1.5 times major equipment costs without any adequate explanation. Member experience suggests this is closer to 3 to4 times equipment costs.
  - EPA continues to assume at least 1 high-bleed pneumatic controller is present at existing source model plants, when the data submitted to EPA pursuant to 40 CFR Part 98, Subpart W suggests this is an incorrect assumption given the low number of high-bleed controllers still being reported. See Attachment C in EPA-HQ-OAR-2021-0317-0808.
  - The EPA deflated costs provided in 2021 dollars to 2019 dollars. As inflation continues to be elevated, this is an unrealistic assumption and not reflective of actual, or anticipated costs. Costs continue to increase across the economy. A more appropriate assumption would be to assume 2021 dollars are equal to 2019 dollars.

7.7 Recordkeeping and Reporting

As more surface site locations electrify pneumatic controllers over time, confirmation of compliance would be easily obtained through any inspection of a site that was connected to grid power, using solar panels or other instrument air system. Based on review of the issued reporting form (EPA-HQ-OAR-2021-0317-1536_content), it appears EPA's intent was to streamline recordkeeping and reporting to only natural gas-driven controllers, which are the affected facility. However, the language proposed within NSPS OOOOb per §60.5420b(c)(6)(i) and EG OOOOc is unclear in this regard. EPA should not require recordkeeping or reporting on pneumatic controllers that are not natural gas-driven.

8.0 Natural Gas-Driven Pneumatic Pumps

8.1 The applicability date for pneumatic pumps under NSPS OOOOb should be the date of the Supplemental Proposal.

While we maintain that the applicability of NSPS OOOOb should apply based on the December 2022 Supplemental Proposal, which included regulatory text for all affected facilities, this is particularly true for natural gas-driven pneumatic pumps. In the preamble (87 FR 74770)[82], EPA even acknowledges the proposed rule varies significantly from what was described in the November 2021 description for pneumatic pumps:

> ***The proposed NSPS OOOOb requirements in this Supplemental Proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition.*** *As noted above, in the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven pneumatic pump. In this Supplemental Proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site.*
>
> ***…****Specifically, the EPA is proposing that pneumatic pumps not driven by natural gas be used.* ***This is a significant change from the November 2021 proposal,*** *which would have required that emissions from pneumatic pump affected facilities be routed to control or to a process, but only if an existing control or process was on site****. (emphasis added)***

In these statements EPA acknowledges that not only did the affected facility definition expand to the collection of pumps at a site, but it also expanded to include piston pumps, which have not historically been regulated in NSPS OOOOa. Additionally, the proposed control options under NSPS OOOOb are completely unexpected and the hierarchy of options proposed would not have been a logical expectation based on the description in November 2021 proposal description. Specifically, operators have had no way of knowing:

1) Piston pumps would be affected facilities under §60.5365b(h).

2) The collection of both piston pump and diaphragm pumps would constitute an affected facility under §60.5365b(h).

3) The control standard would require a zero emissions control or a suite of ongoing certifications to demonstrate feasibility or infeasibility in §60.5393b.

4) Modification and reconstruction have never applied to such small ancillary equipment such as a single piston pump or diaphragm pump.

Therefore, the applicability date for pneumatic pumps under NSPS OOOOb should be the date of Supplemental Proposal.

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[82] Federal Register / Vol. 87, No. 233 / Tuesday, December 6, 2022 / Proposed Rules

8.2 Under NSPS OOOOb, we support the use of non-emitting pneumatic pumps for newly constructed well sites, tank batteries, and compressor stations, but we do not support the hierarchy of options proposed and inclusion of additional certification statements. The standard should be technology neutral similar to the pnuematic controller requirements.

The control options proposed for natural gas-driven pneumatic pumps are the same as those proposed to control natural gas-driven pneumatic controllers, yet the EPA is requiring additional technical demonstrations for pneumatic pumps that are not required for pneumatic controllers. We believe the requirements for natural gas-driven pneumatic pumps should be similar to those proposed for pneumatic controllers and the allowance for routing emissions to a control device which is allowed for pumps be extended to controllers (without any additional technical demonstration).

Furthermore, the hierarchal structure as proposed does not make logical sense as routing emissions to process, which has been a long-standing compliance option under the NSPS, is placed at a lower tier than that of implementing instrument air systems using solar or natural gas. As provided in Comment 12.9, the additional certifications associated with this hierarchy should be removed. The CAA already has provisions for knowing criminal violations related to false statements, which includes reference to false material statement, representation, or certification in/omits material information from/alters, conceals or fails to file or maintain a document filed or required to be maintained under the CAA.

8.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic pumps.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms ‘natural gas-driven pneumatic pump’ and ‘pneumatic pump’ interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic pumps. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric pumps as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(h)(1):

> *For the purposes of §60.5393b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic pumps at a site is increased by one or more.*

We offer the following suggested for modification redline to §60.5365b(h)(2):

> *For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic pumps in accordance with paragraph (h)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven pneumatic pumps at the site in accordance with paragraph (h)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (h)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (h)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic pumps is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of natural gas-driven pneumatic pumps”*

criterion in (h)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of natural gas-driven pneumatic pumps replaced exceeds 50 percent. For purposes of paragraphs (h)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of ~~component~~ natural gas-driven pneumatic pump replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic pump replacement.

(i) If the owner or operator applies the definition of reconstruction in §60.15, reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic pumps exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic pumps at the site. The "fixed capital cost of the new pneumatic pumps" includes the fixed capital cost of all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic pumps replaced, reconstruction occurs when greater than 50 percent of the pneumatic pumps at a site are replaced. The percentage includes all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]. If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic pumps that are replaced, the owner or operator must comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review also apply.

8.3.1 Additional clarifications are required for the proposed requirements for reconstruction of pneumatic pumps.

In review of the proposed regulatory text provided for §60.5365b(h)(2), the following elements of the proposed regulatory text require clarification:

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed.** Similar to natural gas-driven pneumatic controllers, the proposed language in §60.5365b(d)(2)(ii) suggests that reconstructed natural gas-driven pneumatic pumps would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic pumps. We believe it was EPA's intent to not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 proposal.

8.4 Suggested clarifications to certain proposed definitions related to pneumatic pumps in NSPS OOOOb and EG OOOOc.

While EPA expanded the applicability to include piston pumps, EPA did not include a definition for what a piston pump is or is not beyond the definition for natural gas diaphragm pump currently provided. Without this additional definition we request the following technical clarification as it applies to lean glycol circulation pumps. We do not believe it was EPA's intent to include these within the new zero-emitting provisions and historically EPA made it clear that this was not their intent to include these under NSPS OOOOa.

> ***Natural gas-driven diaphragm pump*** *means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a ~~diaphragm~~ pneumatic pump.*

8.5 The provisions included §60.5365b(h)(3) should also reference piston pumps.

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. We support EPA's retention of the provisions proposed in §60.5365b(h)(3) as these pumps will, by their very nature, result in very low and intermittent emissions. In the model plant analysis, the emissions for a single natural gas-driven piston pump is only 0.11 tpy VOC and 0.38 tpy methane. Temporarily used piston pumps would emit even less, which is why they have historically been exempt from the control standards. Such an exemption would be analogous to what also already been granted for temporary natural gas-driven diaphragm pneumatic pumps, and we believe it was EPA's intent to also include piston pumps in this provision.

We offer the following suggested redline to §60.5365b(h)(3):

> *A single natural gas-driven diaphragm pump or piston pump that is in operation less than 90 days per calendar year is not part of an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year in accordance with §60.5420b(c)(15)(i) and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.*

8.6 Natural gas-driven pneumatic pumps in compliance with NSPS OOOOa

NSPS OOOOa requires certain diaphragm natural gas driven pumps to be routed to a control device or process. As such, these pumps are already controlled by at least 95%. EPA has not adequately considered or accounted for how to handle these existing controlled pneumatic pumps within the proposed rules. Specifically, these pumps should meet the requirements of EG OOOOc by continuing to comply with NSPS OOOOa. These pumps should also be excluded from modification and reconstruction under NSPS OOOOa.

8.7 EPA's Model Plant Analysis for Conversion to Electric, Solar or Instrument Air Pumps

EPA assumptions for converting pneumatic pumps to zero-emitting has a distinctly separate set of cost assumptions from the pneumatic controllers even though the same technologies are being proposed for use. While EPA relied on costs from the 2016 and 2021 Carbon Limits report for pneumatic controllers, EPA uses different costs and assumptions as it pertains to converting to electric (assumed to be grid power) and solar pumps, which are not well documented and appear based on old information dating back to 2012. The EPA's economic feasibility analysis for pneumatic pumps presented in file "Supplemental TSD Ch 4 Pneumatic Pump.xlsx" are also only adjusted to 2019 USD from 2012 dollars. Thus, values presented are underestimated by at least 14%.[83]

9.0 Well Liquids Unloading Operations

As we communicated to EPA in our January 31, 2022 letter[84], well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective because there are numerous misconceptions about why and how this activity is conducted. While we support EPA's inclusion of well liquid unloading operations as an affected facility, the regulation should be based solely on the work practice standard outlined in §60.5376b(c)(2) and (d) and should not include a zero-emission limit as provided in §60.5376b(b). To this end, the recordkeeping and reporting requirements must be amended to be a workable framework for operators to assure compliance including removal of the certification statement by an engineer in every instance that venting may occur.

Lastly, the applicability for liquid unloading operations must be designated as the date of the Supplemental Proposal as the recordkeeping requirements were not explicitly known for each event that ocurred prior to the publication. Much of the recordkeeping elements proposed in the December 2022 proposal, including the certification statement by engineer, was not anticipated based on the descriptions in the November 2021 proposal.

9.1 Well liquid unloading operations should be subject to work practice standards and not held to a zero-emission limit.

API supports the proposed alternative measures outlined in §60.5376b(c)(2) and (d), which provide a clear and rational work practice standard based on Best Management Practices (BMPs) that achieve the intent to reduce

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[83] https://www.usinflationcalculator.com/

[84] EPA-HQ-OAR-2021-0317-0808

emissions from liquid unloading of gas wells. These provisions should be considered BSER and should not be considered an exception to the standard as currently proposed in §60.5376b(c).

We appreciate EPA's recognition that solely imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations that in many situations could severely halt natural gas production. For some situations, a certain unloading technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. The work practice standards proposed in §60.5376b(d) allow operators the flexibility needed to minimize emissions from well liquid unloading, while allowing for unexpected situations or outcomes that may occur during the unloading operation that might result in a minimal amount of emissions to be vented.

To be clear, while we support the work practice provisions in §60.5376b(c)(2) and (d), we do not support the provisions proposed in §60.5376b(b) establishing a zero-emission limit on liquid unloading operations as this limit creates undue burden of compliance when EPA has acknowledged it is known that not every liquid unloading operation can technically or safely meet the zero-emission limit. This undue burden is compounded when considering the logistical and practical implementation of the associated recordkeeping, reporting and certification statements also proposed. See also Comment 12.9.

9.2 Additional clarification to the proposed definition of liquids unloading is warranted.

As we previously commented in our January 31, 2022 letter, other well maintenance and workover activities may occur on a well that are distinctly different, require separate specialized equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. EPA must explicitly provide clarification to address these distinctions, within the definition for "liquids unloading" so not to confuse other activities that might occur at a well with the liquids unloading operation provisions as proposed.

Our suggested clarification to the definition of liquids unloading under §60.5430b and §60.5430c is as follows:

> *Liquids unloading means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production. Routine well maintenance activities, including workovers, screenouts, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.*

9.3 The recordkeeping and reporting for liquids unloading operations must be simplified into a manageable framework for operators and streamlined for liquid unloading operations that vent to atmosphere.

The information proposed by EPA within §60.5420b and §60.5420c for the recordkeeping and reporting as it pertains to liquid unloading operations is focused on an operator tracking and certifying techniques and less focused on allowing an operator to perform the necessary procedures to unload liquids accumulated within the wellbore and maintain natural gas production with as minimal emissions as possible. To address this shortfall, we suggest EPA define the data operators should track per unloading operation and remove all superfluous records that generate additional burden for the operator and EPA without added environmental benefit. These suggestions assume that liquid unloading operations are to be conducted using a work practice standard according to our suggestion in Comment 9.1.

The current proposed recordkeeping requirements do not offer a reasonable framework for operators to maintain compliance assurance. In fact, EPA has included a certification by professional engineer for every instance a well unloading operation vents emissions to atmosphere in §60.5420b(c)(2)(ii)(B) and §60.5420b(b)(3)(ii)(B) based on the proposed zero emissions limit standard. This may not be known to an operator until the liquid operation is taking place based on a variety of parameters. For context, a single well affected facility may undergo multiple liquid unloading operations in a single compliance period. For example, one well may necessitate an unloading schedule of four times in a year. Based on best management procedures, three (3) of these events may occur with zero emissions, while one (1) of the events might vent to atmosphere for a short duration using the same technique. The justification provisions in §60.5420b(c)(2)(ii)(B) are untenable when the same technique used on a well may resulted in zero emissions during some liquid operations, but not during all liquid unloading operations in the same compliance period. The fact is that in some instances a well liquid unloading operation may need to vent emissions for short duration, sometimes a little as 30 minutes, to safely perform the liquid unloading operation. We therefore request:

1) EPA remove the additional engineering certification statements under the guise of technical demonstrations. These additional certifications would be unnecessary if the standard followed a work practice procedure (see Comment 9.1).

2) Limit recordkeeping and reporting to liquid unloading operations that result in emissions only. This would reduce the administrative burden for thousands of liquid unloading operation events. This is also consistent with how both Colorado and New Mexico have organized recordkeeping and reporting for their state regulations.

   Our suggestions to streamline and simplify the recordkeeping and reporting for liquid unloading operations is as follows:

> *For each gas well affected facility that conducts liquids unloading operations during the reporting period that resulted in emissions vented to the atmosphere:*
>
> - *US Well ID*
> - *The number of liquids unloading events during the year that resulted in emissions.*
> - *The date and time of each liquid unloading operation where venting occurred.*
> - *The duration of venting in hours.*
> - *Reason venting occurred*

Additional recordkeeping for liquid unloading operations should include:

> *Documentation of your best management practice plan developed under paragraph §60.5376b(d). You may update your best management practice plan to include additional steps which meet the criteria in §60.5376b(d).*

10.0 Compressors

API endorses the comments being submitted by GPA Midstream Association as it pertains to reciprocating and centrifugal compressors and provides the following additional comments.

10.1 Reciprocating and Centrifugal Compressors should be subject to a work practice standards with clear repair and delay of repair provisons instead of an emission standard.

Within Section IV.I.of the preamble (87 FR 74796), the EPA acknowledges *"over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder."* EPA also provides its rationale for the proposed level of excessive leaking (87 FR 747996) as "*the 2 scfm flow rate threshold was established based on manufacturer guidelines indicating that a flow rate of 2 scfm or greater was considered indicative of rod packing failure."* In summary, the EPA anticipates emissions from rod packings over time even from reciprocating compressors that are properly operated and maintained.

Yet, at the same time, EPA proposes to establish the 2 scfm flowrate as a not-to-exceed standard of performance, such that a violation occurs if flow rate exceeds that value (87 FR 74797). In doing so, EPA fundamentally misconstrues the manufacturers recommendations. In practice, exceeding a manufacturer-recommended flow rate is an indication that a repair should be made. Exceeding that rate does not necessarily compromise operability of the unit and, in fact, the values are selected to allow continued operation for the period necessary to arrange for needed repairs to be made. EPA without explanation proposes to transform what in practice constitutes an action level into a regulatory cap that cannot be exceeded without the prospect of incurring a violation. EPA's proposal is at odds with the facts and is an unreasonable reinterpretation of standard maintenance practices.

Therefore, if EPA is intent on setting a numeric standard of performance, the value must be well above the 2 scfm that EPA believes to be the standard manufacturer recommendations. The value must accommodate operations for a reasonable and potentially significant period of time that may be needed to accomplish needed repairs. If EPA takes this path, a reproposal is necessary so that we can know the newly proposed value, understand EPA's rationale, and have an opportunity to submit comments on the record. Alternatively, we believe that the flowrate can be established as a work practice that would trigger a repair obligation rather than constitute a numeric emissions limitation. While it is true that flow can be measured here, it is not technically or economically practicable to install measurement systems that would assure complliance with a numeric emissions limitation. See CAA § 111(h)(2)(B).

10.2 Clarification is required for compressors with multiple cylinders or seals.

In the November 2021 preamble (86 FR 63216), EPA described the rod packing requirements as follows:

> *"We are proposing that BSER is to replace the rod packing when, based on annual flow rate measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. We are proposing that if annual flow rate monitoring indicates a flow rate for any individual cylinder as exceeding 2 scfm, an owner or operator would be required to replace the rod packing."*

In looking at documentation for the dry seal proposed requirements, the Natural Gas Star[85] report where this value was seemingly derived, it is stated, "*During normal operation, dry seals leak at a rate of 0.5 to 3 scfm across each seal (1-6 scfm for a two seal system), depending on the size of the seal and operating pressure…. An example of one type of tandem seal with leak rates ranging between 0.5 to 3 scfm for 1.5 to 10 inch compressor shafts, for compressors operating at 580 to 1,300 psig pressure.*"

In the proposed text provided in §60.5380b or §60.5385b(a), the distinction that the limits are per cylinder or seal is unclear. It would be impratcical for a compressor with multiple cyclinders (reciprocating) or seals (centrifugal) to operate the same as compressor with only a single cyclinder or seal. As the Natural Gas star report documents, it is also impractical to expect the same level of emissions from dry seals for various sized units.

Therefore, EPA must clarify that the emission threshold designated is by cylinder or throw (reciprocating) and per seal (centrifugal). We note that the following suggested redlines for NSPS OOOOb and EG OOOOc are consistent with §95668 (c)(4)(D) of the 2017 California's GHG Emissions Regulations, which this proposed standard was based:

> *§60.5385b(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5393c(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5380b(a)(4)(i): The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section.*
>
> *§60.5392c(a)(1): You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. The volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm.*

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[85] https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/ll_wetseals.pdf

10.3 Conducting annual measurements on temporary compressors is logistically impractical and temporary compressors should be exempt from §60.5365b(b) and (c)(b).

Temporary compressors should be exempt from the monitoring requirments as it would be infeasible to conduct monitoring on a compresor that will be removed from a site after less than a year. Equipment that is intended for temporary use and is not a stantionary source should not not be subject to either NSPS OOOOb and EG OOOOc. API requests EPA make the following clarifications to address this concern:

> *§60.5365b(b): Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart. A centrifugal compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*
>
> *§60.5365b(c): Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart. A reciprocating compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*

10.4 Reciprocating Compressors

While API supports certain aspects of the Supplemental Proposal for reciprocating compressors, addiitonal clarifications must be made. The following amendments, in addition to the items outlined above and in comments submitted by GPA Midstream Association, would alleviate some of the significant technical cocnerns our members have with the proposed requirements.

- **Emissions from reciprocating rod packing vents that are routed to a process or flare should be considered an adequate alternative in reducing emissions.** EPA should continue to allow an option for rod packing vents to be routed to a control device for new, modified and existing facilities. The incremental benefit achieved between monitoring and subsequent repair (if applicable) versus capturing the vent to control device that achieves 95% destruction efficiency has not been substantiated by EPA within their cost benefit analysis. This is especially true for any compressor that already is designed and configured to route rod packing to a flare or other combustion device.

- **EPA should provide additional flexibility for addressing rod packing leaks by allowing operators to forgo annual emission measurements and replace rod packing annually.** Given the sheer number of compressors that will apply to NSPS OOOOb and EG OOOOc, EPA should provide flexibility by allowing operators the option to change out rod packing annually or 8760 hours (whichever comes first), which is similar in approach but more frequent than the current requirements in NSPS OOOO and OOOOa, or to perform the newly proposed annual monitoring and replacement of rod packing if emissions exceed to specific threshold as identified.

- **Repair parameters were omitted from the proposed regulatory text.** The EPA states their intent to define some repair parameters for reciprocating compressors in the preamble (87 FR 74798):

> *"The proposed NSPS OOOOb regulatory text also specifies that flow rate monitoring be conducted in operating or standby pressurized mode, and "repair" and "delay of repair" schedules, in addition to other clarifying requirements. The EPA is proposing to require conducting flow rate measurements during operating or standby pressurized mode because the measured emissions would be representative of actual emissions during operations. Repair schedules are proposed to require repair of equipment in a timely manner to mitigate emissions. Delay of repair would be allowed when owners and operators required more time to repair equipment based on scenarios beyond the owner or operator's control (e.g., issues with availability of equipment or where repair necessitates a compressor shutdown when redundancy of compressors is not available)."*

However, the repair and delay of repair schedules could not be located in the proposed regulatory text. As stated in Comment 10.1, the EPA should establish a monitoring schedule for reciprocating compressors with reasonable repair times. Further, allowances should be incorporated to address situations that delay repairs, appropriately.

California regulations governing rod packing emissions, upon which these proposed regulations are based, require repair within 30 calendar days from the date of the initial emission flow rate measurement. Furthermore, repair of a compressor typically cannot be performed while the compressor is in service, and some situations may arise that warrant delay of repair. We therefore request EPA amend the provisions in §60.5380b and §60.5385b to accommodate a work practice standard that includes clear provisions for repair or replacement and delay of repair or replacement that is consistent with §60.5397b(h)(3).

10.5 Centrifigal Compressors

10.5.1 Clarification is requested to the definition of centrifugal compressor.

Within the definition "centrifugal compressor" in §60.5430b and §60.5430c, EPA describes the compressor as "*discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers."* The phrasing of "significantly higher-pressure" should be further delineated to eliminate ambiguity. If left undefined the regulated operator does not have a clear understanding of what is affected and what is not affected.

The definition of centrifugal compressor as it was used in the initial NSPS OOOO rulemaking only affected wet-seal centrifugal compressors, which includes a relatively small population of affected facilities that were generally considered to discharge significantly higher-pressure natural gas. With the expansion of the NSPS OOOOb and EG OOOOc to also include dry seal compressors, which are more widely utilized, additional clarity is warranted.

In the oil and natural gas industry, compressors that boost natural gas pressures are normally designed to discharge natural gas greater than 300 pounds per square inch differential (psid). The original intent of EPA including this language was to exclude smaller compressors with low differential pressure (e.g., process compressors, vapor recovery units, and other low pressure service units). With this consideration, API recommends that EPA update §60.5430b to include a definition of significantly higher-pressure and includes the following language:

> *Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart. For the purposes of §60.5380b, significantly higher-pressure means having a design pressure differential greater than 300 pounds per square inch differential (psid).*

10.5.2 The emission limit for dry seal compressors should properly account for compressor size.

The origin of and basis for the proposed three (3) scfm limit for dry seal compressors is not provided within the EPA docket and associated references. API suspects that the genesis of this number did not consider variable compressor sizes, resulting in a low value for the standard that is not representative of all operations. In Section IV.G.1.b.iii of the Federal Register, the origin of this value is as follows: *"The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in §95668(d)(4-9), California's Regulations*[86] *for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate*[87]*."* Research into the underlying sources of the CARB regulation does not yield supporting information for the development of the 3 scfm standard. EPA should supplement the docket with information to support why this value is representative of the population of dry seal compressors across the nation (taking into consideration compressor size variability).

Larger compressors usually have larger shaft diameters, higher operating speeds, and greater operating pressures. These three variables all contribute factors to the amount of gas that might ultimately slip through the seals. The combination of these three factors will usually yield higher leak rates from seals as measured on a volumetric basis, thus larger compressors will have a higher baseline for normal operations.

Based on data submitted to the EPA pursuant to 40 CFR Part 98, Subpart W for the 2021 calendar year, dry seal compressor driver power output ranged between 5 – 42,000 horsepower and for wet seals the compressor driver power output ranged between 40 – 53,665 horsepower.[88] We do not believe compressors associated with the higher end of this range should be expected to operate the same as compressors closer to the lower end of this range. Table 2provides more details on our short analysis showing variable sizes of both dry and wet seal compressors as reference.

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[86] https://ww2.arb.ca.gov/sites/default/files/2020-03/2017 Final Reg Orders GHG Emission Standards.pdf

[87] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf, page 100.

[88] Information was extracted from EPA's Envirofacts database using the GHG query builder: https://enviro.epa.gov/query-builder/ghg.

Table 2. Variation in Compressor Driver Output as Reported under EPA's Greenhouse Gas Reporting Program for Calendar Year 2021

Compressor Horsepower Driver Details as reported to EPA for Calendar Year 2021	Count of Compressors in Dataset	Compressor driver power output (Horsepower)		
		Average	Minimum	Maximum
Dry Seals				
Onshore natural gas processing	310	6,427	5	38,000
Onshore natural gas transmission compression	812	14,431	144	42,000
Underground natural gas storage	19	9,817	5,700	15,280
Wet Seals				
Onshore natural gas processing	199	9,426	40	53,665
Onshore natural gas transmission compression	345	5,027	990	30,000
Underground natural gas storage	22	3,910	1,275	9,800

10.5.3 Additional clarification is needed regarding the volumetric flow.

Both wet seal and dry seal systems often use an inert gas, such as nitrogen, for system blankets at positive pressure. That nitrogen vents through the same vent as the seal gas. So measured total vent rates may be overestimating the amount of methane or VOC being vented to atmosphere. Actual vent rates of methane and VOC could be under the standard, but the total volumetric flow could be over due to the nitrogen blanket. EPA should make clear that the standard could be interpreted as either total volumetric flow or methane and VOC flow depending on which method of monitoring is employed.

EPA should also expand the volumetric flow measurement options to allow for alternative ways to obtain the methane and VOC flow:

- Use of thermal mass meter or ultrasonic meter readings in conjunction with gas composition samples to calculate methane and VOC flow, or
- Flow balance equations (i.e., if the amount of inert gas into the system is metered, then that volume could be subtracted from the total flow measurement, thus yielding the methane and VOC only flow.)

10.5.4 The wet seal centrifugal compressor requirements must be clarified between NSPS OOOOb and EG OOOOc.

It is unclear why the standards between NSPS OOOOb and EG OOOOc for centrifugal compressor standards are different:

- NSPS OOOOb – Dry seal compressors and "self-contained wet seal compressors" can only comply with volumetric standard. All other wet seal compressors can only comply with the 95% capture and control requirement.
- EG OOOOc – Any wet seal compressor can either comply with volumetric standard or reduce emissions by 95% through a control standard.

The implications of the NSPS OOOOb regulations seem to be that the 3 scfm volumetric standard is equivalent to the 95% capture and control requirement. If this is the case, then it stands to reason that all centrifugal

compressors should be able to choose to comply with either the volumetric standard or the 95% capture and control practice.

If owners of centrifugal compressors had the option to comply with either standard, it obviates the need for a specially defined class of compressors: “Self-contained wet seal compressors.” Removing this definition from the rule would result in a more simple and straightforward understanding of the rule requirements. API proposes the NSPS OOOOb standards mimic the EG OOOOc standards.

10.5.5 The proposed requirements for Wet Seal Centrifugal Compressors do not consider our previous comments regarding the unique equipment design in the Alaskan North Slope.

On the Alaska North Slope (ANS) there is not a market for natural gas sales. Most of the gas that is produced with the oil is separated and either used as a fuel or is compressed (using large wet seal compressors) to be reinjected back down hole for gas lift or enhanced oil recovery. The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.

Wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures most of the gas by volume then routes that gas to a flare, as described in our January 31, 2022 comment letter[89]. The ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum / tank, where any remaining entrained gas breaks out and is vented to atmosphere. In 2010, EPA’s Natural Gas Star[90,91] program, in conjunction with BP, conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis concluded that the sour seal oil degassing design employed on the ANS has greater than 99% emission control by volume. This same study is also cited by the CARB regulations references. It would stand to reason that this system of gas capture and control should be allowable to use the volumetric standard.

In summary, wet seal compressors with the sour seal oil traps in Alaska as described above, route the gas to the flare, not to the “compressor suction.” Because of this, these compressors would seemingly not meet the definition of “self-contained wet seal compressor.” However, there is language in that definition which suggests that the purpose of that definition is that degassed emissions do not route to atmosphere as proposed in §60.5430b and §60.5430c (***emphasis added***). Therefore, API offers the following redline for the definition of self-contained wet seal centrifugal compressor:

> *Self-contained wet seal centrifugal compressor means a wet seal centrifugal compressor system which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to either another process or combustion device* ~~*that is a closed process that ports the degassing emissions to the natural gas line at the compressor suction*~~ *(**i.e., degassed emissions are recovered**). The de-gas emissions are routed back to* ~~*suction*~~ *a process or combustion device directly from the intermediate closed degassing process* ~~*degassing/sparging chambers*~~*; after the intermediate closed process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.*

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[89] EPA-HQ-OAR-2021-0317-0808

[90] https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf

[91] https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf

Alternatively, as outlined in Comment 10.5.4, EPA could allow all centrifugal compressors the option to comply with the volumetric standard thereby obviating the need for a special definition for a "self-contained wet seal compressor."

11.0 Leak Detection and Repair at Gas Processing Plants

API supports EPA's proposal for bimonthly OGI monitoring for equipment leaks at gas processing plants. We also support incorporation of NSPS Vva into NSPS OOOOb and EG OOOOc as an alternative monitoring option with the additional simplifications EPA has proposed. While API also generally supports the use of Appendix K for OGI monitoring at gas processing plants, we have several comments with respect to proposed Appendix K as provided in Attachment A, which are in direct response to EPA's solicitations within the preamble.

In addition to the above items, API offers the following comments concerning leak detection and repair requirements at gas processing plants.

11.1 Closed vent systems should be monitored annually using OGI or Method 21.

EPA is proposing initial and bi-monthly OGI or quarterly Method 21 monitoring of closed vent systems which are increased monitoring frequencies when compared with the existing annual Method 21 monitoring under NSPS OOOO, NSPS OOOOa, NSPS Vva, and other LDAR regulations. API's previous comments on this topic[92] were intended to voice support for the use of OGI in monitoring closed vent systems and did not fully consider the implications and minimal environmental benefits of more frequent monitoring.

Closed vent systems have historically been subject only to initial and annual inspections due to their low leak rates. Closed vent systems rarely leak because of the small number of components and lack of constantly moving parts. The hard piping or ductwork in closed vent system do not experience the same wear and tear and potential for leaks as moving parts that generate friction. While OGI does not have the same proximity challenges as Method 21, more frequent monitoring of closed vent systems would still be impractical for both methods as parts of closed vent systems are considered difficult to monitor. More frequent inspections for closed vent systems at gas plants under NSPS OOOOb and EG OOOOc would also be more stringent than the requirements for refineries and chemical plants. Therefore, API recommends that for closed vent systems, hard piping be subject to an initial Method 21 or OGI inspection and annual AVO inspections and ductwork be subject to an initial Method 21 or OGI inspection and annual Method 21 or OGI inspections. If EPA decides to finalize the increased monitoring frequency for closed vent systems, they must provide additional justification including the additional environmental benefits expected from more frequent monitoring of equipment that rarely leak.

Emissions detected from closed vent systems do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented. See Comment 5.1 for a more detailed discussion.

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[92] EPA-HQ-OAR-2021-0317-0808

11.2 The lack of a VOC or methane concentration threshold expands monitoring requirements with minimal, if any, environmental benefit.

As API noted in its prior comments[93], EPA should retain the current 10 percent by weight threshold for VOC and propose a similar concentration threshold for methane, which we suggested as 1 percent by weight threshold for methane. In the Supplemental Proposal, EPA is proposing that monitoring apply to each piece of equipment "that has the potential to emit methane or VOC", which is effectively a zero-applicability threshold for both methane and VOC.

Some streams at gas processing plants contain methane or VOC but in such low concentrations that monitoring would be meaningless as it would likely always result in no detected emissions. Examples of such streams include but are not limited to purity ethane, acid gas, ancillary chemicals, wastewater, and recycled water. The proposed monitoring of additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with minimal, if any, environmental benefit.

In its existing LDAR regulations, EPA has recognized and reaffirmed the need for concentration thresholds to achieve cost-effective emission reductions. The agency has not provided sufficient justification for deviating from this longstanding practice with this rulemaking. Based on an initial review of EPA's TSD[94] from the November 2021 Proposal, API notes the following about EPA's analysis:

- EPA considers only components in VOC service and non-VOC service, which the agency appears to define as follows:

> *"In VOC service" is defined as a component containing or in contact with a process fluid that is at least 10 percent VOC by weight or a component "in wet gas service", which is a component containing or in contact with field gas before extraction. "In non-VOC service" is defined as a component in methane service (at least 10% methane) that is not also in VOC service.*

- EPA estimates VOC and methane emissions and therefore emission reductions and cost-effectiveness using only the following composition ratios identified in Table 10-8 of the TSD:

Component Service	Methane: TOC	VOC: TOC
VOC Service	0.695	0.1930
Non-VOC Service	0.908	0.0251

- EPA appears to treat the "potential to emit to methane" as equivalent to "in non-VOC service" in evaluating control options:

> *In addition to selecting one of the LDAR programs above, the EPA considered which components would be subject to the LDAR program. The current NSPS applies to components in VOC service (Option A). The EPA considered expanding the applicability to include components that have a potential to emit methane, which would add the components classified in this document as non-VOC service components (Option B).*

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[93] EPA-HQ-OAR-2021-0317-0808

[94] EPA-HQ-OAR-2021-0317-0166

Therefore, EPA does not appear to fully consider the cost-effectiveness of a potential to emit applicability threshold. API reiterates that EPA should retain the current 10 percent by weight threshold for VOC and establish a similar concentration threshold for methane (suggested as 1 percent by weight). Refer also to Attachment A.

In Comment 11.3, API offers recommended redlines to address this concern. Regarding how to determine when a piece of equipment is not subject to monitoring, the language in §60.5400b(a)(2) should also be revised as appropriate.

11.3 EPA should clarify which equipment is included in the evaluation of capital expenditure.

The definition of equipment is unclear on which equipment is considered when evaluating whether a capital expenditure occurred because capital expenditure is a definition, not a standard or requirement. This lack of clarity could lead to varying interpretations and uncertainty on whether a capital expenditure occurred. For other regulations, EPA has clarified the scope of equipment considered for the affected facility[95]. For leak detection and repair, an appropriate scope would be to apply the same definition of equipment to the capital expenditure evaluation as the standards and requirements. Therefore, the definition of equipment should clearly specify it also applies to capital expenditure.

To address this and the previous comment, API offers the following recommended redlines to definitions in §60.5430b.

> *Equipment, as used in the standards and requirements and for purposes of evaluating capital expenditure in section 60.5365b(f)(1) of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector ~~that has the potential to emit~~ in methane or VOC service and any device or system required by those same standards and requirements of this subpart.*
>
> *In methane service means that the piece of equipment contains or contacts a process fluid that is at least 1 percent methane by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in methane service.)*
>
> *In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in VOC service.)*

12.0 Overarching Legal Issues

12.1 The new source trigger date should be December 6, 2022, the date the Supplemental Proposal was published in the Federal Register.

In a memorandum associated with the Supplemental Proposal, EPA "solicits comments on whether CAA § 111(a) provides EPA discretion to define 'new sources' based on the publication date of the Supplemental Proposal and,

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[95] U.S. EPA Applicability Determination Index Control Number: 0600027, Modification and Capital Expenditure Calculations, dated February 9, 2001.

if so, whether there are any unique circumstances here that would warrant exercising of such discretion in this rulemaking by the EPA."

API believes that not only does CAA § 111(a) allow EPA to define the new source trigger date based on the publication date of the Supplemental Proposal, but also in fact requires it. Further, as API provides below, there are significant circumstances here that would warrant EPA altering the new source trigger date to December 6, 2022.

As explained in our January 31, 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) on the original NSPS OOOOb and EG OOOOc proposed rule, the original proposal was fundamentally incomplete because no proposed regulatory text was published or otherwise made available at the time of proposal. As a result, that proposal could not serve to set the new source trigger date for new requirements described in the proposed rule.

In the Supplemental Proposal, EPA reasserted that, except for newly proposed standards in the Supplemental Proposal (such as the standards for dry seal centrifugal compressors), the new source trigger date will be the date the original proposal was published in the Federal Register. EPA explains that "CAA Section 307(d)(3) specifies the information that a proposed rule under the CAA must contain, such as a statement of basis, supporting data, and major legal and policy considerations; the list of required information does not include proposed regulatory text." (87 Federal Register (FR) R 74716).

EPA further explains that "the Administrative Procedures Act (APA), which governs most Federal rulemaking, does not require publication of the proposed regulatory text in the Federal Register" and instead specifies that "notice of proposed rulemaking shall include ''*either* the terms or substance of the proposed rule *or* a description of the subjects and issues involved.'' (Emphasis added)." *Id*. EPA concludes that "the APA clearly provides flexibility to describe the ''subjects and issues involved'' as an alternative to inclusion of the ''terms or substance'' of the proposed rule." *Id*.

As an initial matter, EPA's analysis on this point indicates that EPA believes the CAA and the APA provide the flexibility to select November 15, 2021 as the trigger date for new sources, but nothing in EPA's analysis specifically concludes or determines that it must use the November 15, 2021 date. API believes that EPA's rationale for using November 15, 2021 remains flawed for three reasons. The lack of regulatory text (which was neither in the Federal Register notice nor otherwise made available in the docket prior to the close of the comment period) prevents the original proposal from setting the new source trigger date.

First, the CAA § 111(a)(2) definition of "new source" uses the term "proposed *regulations*" in defining the new source trigger date. As we explained in our comments on the original proposal, a preamble unaccompanied by regulatory text is not a "regulation." Here, the preamble to the original proposal was simply a description of the proposed regulations, but by itself did not constitute a proposed regulation because nothing in the preamble was intended by the Agency to constitute an enforceable legal obligation. And it could not, as EPA co-proposed multiple concepts for singular facility types in the November 2021 proposal and requested comment that informed the November 2022 Supplemental Proposal's regulatory text.

For example, in the November 2021 proposal, EPA co-proposed quarterly and semi-annual fugitive emissions surveys for well sites with baseline emissions of 3 or more and less than 8 tons per year of methane. EPA then abandoned the baseline emissions approach in the November 2022 Supplemental Proposal in favor of an equipment threshold. In another example, EPA co-proposed to define affected well facilities in two ways for purposes of the liquids unloading standards. Under one approach, every well that undergoes liquids unloading would be an affected facility; under the other approach, the affected facility would be limited to wells that

undergo liquids unloading that is not designed to eliminate venting. These co-proposals, while limited to a subset of the affected facilities, evidence that EPA intended the November 2021 proposal to be conceptual and a means of informing the November 2022 regulatory text.

The November 2022 proposal is complex and requires affected facilities to parse complicated standards that will inform significant capital expenditures and expensive compliance programs. Given the ultimate complexity of the November 2022 regulatory text and scope of impact, the November 2021 proposal's conceptual offerings did not put the regulated community on notice of the "regulations" in any meaningful way that could inform billions of dollars in capital expenditures and compliance program development. Instead, the regulatory text made available in conjunction with the Supplemental Proposal comprises the proposed regulation because that regulatory text defines the enforceable legal obligations that EPA proposes to impose under this rule.

Thus, even if the original proposal may have satisfied the nominal procedural requirements specified by CAA § 307(d) and APA § 553(b) (which it does not for the reasons explained below), the original proposal was not a proposed "regulation" for purposes of setting the new source trigger date under CAA § 111(a)(2). This is particularly true in light of the clear purpose of CAA § 111(a)(2), which is to put affected facilities that are constructed, reconstructed, or modified after the date of a proposed regulation on notice of the requirements that will apply to those facilities upon the effective date of the final regulation. The absence of proposed regulatory text in the original proposal prevents such affected facilities from knowing with reasonable certainty the precise requirements that might actually apply, and thus prevents them from adequately planning for compliance.

Second, EPA's interpretation of CAA § 307(d) and APA § 553(b) is unreasonable and does not make sense in the broader context of these provisions. For example, EPA argues that the required content of a proposed rule specified in CAA § 307(d)(3) does not expressly require regulatory text, but the corresponding content requirements for a final rule (specified in CAA §§ 307(d)(4)(B)(i), (6)(A), and (6)(B)) similarly do not expressly require regulatory text. By EPA's reasoning, that means that the Agency is not required to provide regulatory text as part of a final rule. That is nonsensical. This is particularly true because the record for judicial review is limited to the materials prescribed by CAA §§ 307(d)(3), (d)(4)(B)(i), (6)(A), and (6)(B). CAA § 307(d)(7)(A). If proposed and final rules do not need to include regulatory text, then regulatory text would not be subject to judicial review. That is contrary to reason and the clear intent of the law.

In short, it is simply not plausible to argue that because CAA § 307(d) does not expressly require a proposed rule to include regulatory text; EPA is not required to make proposed regulatory text available at the time of the 2021 "proposal". When considered as a whole, CAA § 307(d) plainly requires rule text to be available.[96]

Third, and more broadly, EPA and the Biden administration made a political judgment to rush issuance of the original proposed rule because the rule constitutes a prominent plank of the administration's climate change regulatory agenda, and it was deemed expedient to issue the proposed rule in conjunction with the 2021 Conference of the Parties to the United Nations Framework Convention on Climate Change in Glasgow, Scotland.[97] The fact that EPA acknowledged the original proposal would require a Supplemental Proposal with

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[96] EPA cites *Rybachek v. USEPA*, 904 F.2d 1276, 1297 (9th Cir. 1990) as supporting its position that proposed regulatory text is not necessary. That case is inapposite because the court relies on APA § 553(b)(3). While that provision applies to this rulemaking, the more specific requirements of CAA § 307(d) control here.

[97] EPA's press release for the original proposal is available at U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health | US EPA (""As global leaders convene at this pivotal moment in Glasgow for COP26, it is now abundantly clear that America is back and leading by example in confronting the climate crisis with bold ambition," said EPA Administrator Michael S. Regan**.** "With this historic action, EPA is addressing existing sources

actual regulatory text is plain evidence of the rush. The sheer size of the Supplemental Proposal – 146 pages in the Federal Register, *without* regulatory text (which is provided in the docket) – is further mute evidence of the incomplete nature of the original proposal.

We recognize that every administration has the right to set and implement its regulatory agenda. However, this Administration's desire to expedite issuance of the original proposed rule led to compromises in the usual regulatory procedures, including the decision not to make proposed regulatory text available. It would be unreasonable for affected facilities to bear the burden of those compromises. It is also arbitrary and capricious for EPA to decide to issue an admittedly incomplete proposed rule to satisfy political objectives, and, at the same time, assert that it is somehow complete enough to constitute a "proposed rule" that sets the new source trigger date.

As shown in the analysis above, nothing allows or requires EPA to utilize the November 15, 2021 date. Further, the failure of EPA to provide regulatory text in the November 15, 2021 proposal is reason enough for EPA to "warrant exercising" any discretion it does have with respect to the deadline.

Further, by utilizing November 15, 2021 as the relevant demarcation date, EPA will be including a significant number of sources that were new, modified, or reconstructed between November 15, 2021 and December 6, 2022. For a significant number of the affected facilities, operators will be required to retrofit those new, modified or reconstructed sources to comply with the regulations, including regulations not known to operators at the time of construction, modification or reconstruction. Many of these requirements involve either: (1) substantial capital expenditures for equipment (e.g., instrument air skids and/or generators for use of non-emitting pneumatic controllers); (2) engineering design (e.g., storage tanks, design for any covers and closed vent systems, among others); (3) acquisition (along with all other operators) of a substantial number of part and equipment (e.g., flow meters, calorimeters; and (4) substantial in-field resources for retrofits. Not knowing with reasonable certainty what the final rule would require would significantly complicate implementation of compliance measures, cause the rule to be much more costly for such sources than EPA predicts, and frustrate the regulatory purpose of setting the new source trigger date at the date of proposal (which clearly is intended to provide reasonable notice of the ultimate requirements so that planning can be done at the time of construction, reconstruction, or modification.

In addition, since the onset of the COVID pandemic and continuing to this day, there have been substantial supply chain disruptions, difficulty with obtaining parts and equipment and difficulty with finding personnel (either consulting or for employment) that can assist with implementation of the rule. These supply chain and personnel issues will increase given the extensive nature and reach of NSPS OOOOb alone (given all the operators that will need to comply) – not even accounting for other recent regulatory developments at the state and federal level (e.g., BLM waste prevention rule, Colorado regulatory requirements, and New Mexico requirements – to name a few). EPA will compound this supply chain and personnel concern by maintaining November 15, 2021 as the new source trigger date. EPA's motivation is further obscured given the sources constructed, modified or reconstructed between November 15, 2021 and December 6, 2022 are potentially subject to NSPS OOOOa and may ultimately be subject to EG OOOOc. Thus, API believes that EPA not only has the discretion but the requirement to assign December 6, 2022 as the new source applicability date. Even if this were not required, there is ample basis for EPA to do so for all the reasons previously stated.

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from the oil and natural gas industry nationwide, in addition to updating rules for new sources, to ensure robust and lasting cuts in pollution across the country. By building on existing technologies and encouraging innovative new solutions, we are committed to a durable final rule that is anchored in science and the law, that protects communities living near oil and natural gas facilities, and that advances our nation's climate goals under the Paris Agreement."").

12.2 EPA's interest in promoting Environmental Justice is laudable, but EPA must be mindful of the Clean Air Act's boundaries in advancing these goals.

API explained in its comments on the original proposal that we support EPA's attention to potential Environmental Justice (EJ) issues and agree with EPA that the emissions standards prescribed by this rule will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The oil and natural gas industry's top priorities are protecting the public's health and safety – regardless of race, color, national origin, or income – and the environment. We strive to understand, discuss, and appropriately address community concerns with our operations. We are committed to supporting constructive interactions between industry, regulators, and surrounding communities/populations including those that may be disproportionately impacted.

Our comments also explained that, while API supports EPA's EJ goals, the Agency did not provide sufficient detail in the 2021 Proposal to allow API to comment in a meaningful way. EPA has provided additional clarity on two key EJ provisions in the Supplemental Proposal. They are addressed separately below.

12.2.1 Consideration of EJ Impacts in CAA § 111 Standard Setting

First, EPA proposes to require consideration of impacted communities when setting existing source emissions standards that take into consideration remaining useful life and other factors (RULOF). For example, if "a designated facility could be controlled at a certain cost threshold higher than required under the EPA's proposed revisions to the RULOF provision, and such control benefits the communities that would otherwise be adversely impacted by a less stringent standard, the state in accounting for RULOF could choose to use that cost threshold to apply a standard of performance." (87 FR 74824).

EPA believes that it has authority to prescribe such a requirement because "CAA section 111(d) does not specify what are the "other factors" that the EPA's regulations should permit a state to consider", and thus the Agency may "interpret[] this as providing discretion for the EPA to identify the appropriate factors and conditions under which the circumstance may be reasonably invoked in establishing a standard less stringent than the EG." *Id*.

EPA further explains that part of its responsibility in reviewing the adequacy of state CAA § 111(d) existing source emissions control programs is to "determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives." *Id*. "The EPA finds that a lack of consideration to [disparate health and environmental impacts] would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally." *Id*.

Lastly, EPA explains that the "requirement to consider the health and environmental impacts in any standard of performance taking into account RULOF is consistent with the definition of "standard of performance" in CAA section 111(a)(1)" which "requires EPA to take into account health and environmental impacts in determining the BSER." *Id*.

We applaud and support EPA's overall objective of addressing potential disparate impacts. But we are concerned that the Agency's proposal to require such impacts to be addressed when RULOF is considered in setting state standards is not legally supportable.

To begin, the term "other factors" is a generic term in and of itself. But as used in the context of CAA § 111(d), that term does not reasonably mean that EJ may be considered in standard setting. First, CAA § 111(d)(1) states that EPA's regulations "shall permit" states to consider RULOF in setting existing source emissions standards. This

language places responsibility on the states, in the first instance, to determine the “other factors” they deem relevant in setting standards upon consideration of RULOF. EPA’s role is to review the state determination and not to preemptively specify what factors a state may or may not consider. If a state’s identification and consideration of other factors is reasonable, then EPA cannot reject the state’s determination on the grounds that EPA believes the term “other factors” should be given a different meaning. EPA’s proposed approach is inconsistent with the role Congress intended the states to fulfill as part of the CAA’s broader “cooperative federalism” scheme.

Second, the term “other factors” must be interpreted in context. By specifying that states may consider “remaining useful life,” Congress indicated that source-specific factors are relevant to the states’ determinations. Since the term “other factors” is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term “other factors” must be construed in a similar light. This interpretation is particularly true given that “standards of performance” under CAA § 111(a)(1) are technology-based standards that reflect the best system of emissions reduction determined applicable to affected facilities. EPA’s proposed interpretation of “other factors” is inconsistent with this source-specific, technology-based regulatory scheme.

Third, unlike other standards under the CAA, CAA § 111 does not require or allow for standards to be based on an assessment of impacts regarding health or the environment. Where the CAA confers such authority, it does so expressly and usually in a context where criteria exist to determine the adequacy of such standards. For example, CAA § 112(f) requires impacts to health and the environment to be considered in determining whether “MACT”[98]-based NESHAPs are adequately protective to health and the environment. The statute specifies that EPA must provide an “ample margin of safety,” as defined in the Benzene Waste NESHAP. CAA § 112(f)(2)(A), (B). The Title I air quality program is also designed in this fashion – with the National Ambient Air Quality Standards (NAAQS) established as the benchmark for acceptable air quality and the guidepost for formulating appropriate state programs.

Here, CAA § 111 does not provide any indication that EPA must or may consider health or environmental impacts associated with air emissions from affected facilities in determining BSER and in setting emissions standards. For over 50 years, CAA § 111 has properly been construed as a technology-based program designed to prescribe standards based primarily on consideration of the best available technologies that are adequately demonstrated and not cost prohibitive. EPA’s goals here are important but would require standards to be based on impacts analyses of air emissions from affected facilities – an approach that is not incorporated into the CAA § 111 standard setting process.

EPA also states that not considering impacts would be “antithetical to the public health and welfare goals of CAA Section 111(d) and the CAA generally.” There is no doubt that protecting public health and welfare are overarching goals of the CAA. That aspiration does not in itself confer regulatory authority that is not otherwise prescribed by the statute. Congress carefully designed the regulatory tools it intends EPA to use to accomplish an adequate degree of protection to health and welfare. For the reasons explained above, CAA § 111(d) does not require or allow for consideration of health or environmental impacts in standard setting.

Lastly, EPA argues that considering EJ impacts in state standard setting “is consistent with the definition of “standard of performance” in CAA Section 111(a)(1)” and that states must consider such impacts “just as the EPA is statutorily required to take into account these factors in making its BSER determination.” *Id*. at 74824. More specifically, EPA asserts that the definition of “standard of performance” “requires the EPA to take into account health and environmental impacts in determining the BSER.” *Id*. We respectfully disagree, as there is no language

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in the CAA § 111(a)(1) definition of “standard of performance” that requires or allows health or environmental impacts associated with air emissions from affected facilities to be factored into standard setting.

As explained above, that definition requires standards of performance to primarily be based on technology and cost considerations. The only exception is that “nonair quality health and environmental impact[s] and energy requirements” also must be taken into account in setting standards of performance. CAA § 111(a)(1). The statute thus is clear that the only “health and environmental impacts” that may be considered in setting a standard of performance are ***nonair*** health and environmental impacts. That provision traditionally has been interpreted to require EPA to consider cross-media impacts (e.g., wastewater created by an air emissions scrubber) so as not to create a different environmental issue through technical requirements meant to address air quality. Because the analysis that EPA would require here would focus on air emissions impacts, it cannot be grounded in the requirement to consider ***nonair*** quality health and environmental impacts. Moreover, because the statute specifies that only nonair quality health and environmental impacts may be considered in standard setting, EPA is precluded from interpreting general language in CAA § 111(a)(1) or 111(d)(1) as somehow authorizing consideration of air quality-based health or environmental impacts.

For all of these reasons, EPA should reconsider the proposed requirement to require consideration of EJ impacts when states or EPA implement the RULOF provision.

12.2.2 Requirement that states provide for “meaningful engagement” in their CAA § 111(d) programs.

The Supplemental Proposal provides further details and additional explanation of the proposal to require states to provide for “meaningful engagement” as part of their CAA § 111(d) regulatory programs. According to EPA, “[t]he fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare” (87 FR 74827). As a result, EPA asserts that “a key consideration in the state’s development of a state plan, in any significant plan revision, and in the EPA’s development of a Federal plan pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare.” *Id*. “A robust and meaningful public participation process during plan development is critical to ensuring that the full range of these impacts are understood and considered.” *Id*.

The “meaningful engagement” requirement is grounded in the assertion that “a fundamental purpose of the Act’s notice and public hearing requirements is for all affected members of the public, and not just a particular subset, to participate in pollution control planning processes that impact their health and welfare.” *Id*. at 74828-9. In explaining the legal basis for this requirement, EPA states that “[g]iven the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, the EPA believes it is reasonable to require meaningful engagement as part of the state plan development public participation process in order to further these objectives.” “Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations ‘‘as are necessary to carry out [its] functions under [the CAA].’’ The proposed meaningful engagement requirements would effectuate the EPA’s function under CAA section 111(d) in prescribing a process under which states submit plans to implement the statutory directives of this section.” *Id*. at 74829.

API supports full and fair public process in the development and implementation of CAA programs, including state CAA § 111(d) programs. All affected entities should have a reasonable opportunity to know about and participate in the development of regulations that affect their interests. In that light, we offer the following comments on the proposed “meaningful engagement” requirement.

First, CAA § 111(d) states only that EPA shall establish a "procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan." This requirement to establish a "procedure" for "submit[ting] … a plan" unambiguously is directed only at the review and approval process as between the states and EPA and is not directed at the plan development process that must be followed by the state. In other words, CAA § 111(d) directs EPA to emulate only some of the CAA § 110 requirements – not all of them.

Thus, CAA § 111(d) does not allow EPA to impose upon the states any measures related to the process by which they develop their plans. It only provides authority to set up a process by which EPA reviews and approves the adequacy of standards of performance and the measures adopted by the states to implement and enforce such standards.

Second, to the extent that a "reasonable notice" standard applies to the development of state plans under CAA § 111(d), it is the states' responsibility to ascertain what is reasonable – not EPA's. CAA § 111(d) is one of many CAA provisions where Congress intentionally split responsibility between EPA and the states. Indeed, under this "cooperative federalism" scheme, "air pollution control at its source is the primary responsibility of States and local governments." CAA § 101(a)(3). In the earliest days of the CAA, the U.S. Supreme Court confirmed that the CAA "gives the Agency no authority to question the wisdom of a State's choices of emission limitations" if the limitations accomplish the goals of the CAA. *Train v. NRDC*, 421 U.S. 60, 79 (1975).

Implicit in the notion of cooperative federalism is that states not only have wide latitude to determine appropriate emissions limitations, but also have similarly wide latitude in the legal and regulatory processes by which such limitations are established. Thus, to the degree a "reasonable notice" obligation is imposed upon the states by CAA § 111(d), the states have primary authority and responsibility to determine how to implement this requirement. While EPA has responsibility to review and approve state programs, it may not require states to follow what it believes to be the most reasonable notice procedures. Instead, EPA must approve any state notice requirements that are facially reasonable, even if those are not the procedures EPA itself would have selected.

Third, even if EPA has authority to define what constitutes "reasonable notice" during the development of state plans, the proposed "meaningful engagement" requirement goes beyond what EPA may reasonably require. To begin, the term "notice" unambiguously means notification of those with interest in the matter at hand. The proposed requirements to engage with particular groups in particular ways (e.g., states must seek to overcome "barriers to participation" by "pertinent stakeholders") and make targeted outreach go well beyond the nominal statutory obligation of notification. EPA may "think [its] approach makes for better policy, but policy considerations cannot create an ambiguity when the words on the page are clear." *SAS Institute Inc. v. Iancu*, 138 S. Ct. 1348, 1358 (2018). Congress has imposed no explicit requirements and stated no intent in CAA § 111 or anywhere else in the CAA related accomplishing any particular environmental justice goals or outcomes. The word "notice" cannot carry as much meaning as EPA believes it should.

As for CAA § 301, it has long been understood that that provision does not "provide [EPA] Carte blanche authority to promulgate any rules, on any matter relating to the Clean Air Act, in any manner that the [EPA] wishes." *North Carolina v. EPA*, 531 F. 3d 896, 922 (D.C. Cir. 2008) (internal quotes and citations omitted). Here, CAA § 301(a)(1) is inapplicable because creating a new category of procedural requirements is not "necessary" for the Administrator "to carry out his functions under this chapter." CAA § 301(a)(1). As noted above, EPA's intentions are commendable. But the proposed "meaningful engagement" procedures are not "necessary" as that term is used in CAA § 301.

Lastly, EPA's proposed "meaningful engagement" procedures are are not adequately clear and objective. As noted above, Congress has not spoken in the CAA to the issue of environmental justice. EPA and interested parties are without guidance as to whether the issue should be addressed under the CAA and, if so, how.[99] Moreover, EPA's criteria for determining the adequacy of state "meaningful engagement" efforts are vague and EPA's authority under its proposed rules to accept or deny a state's efforts is not bounded by any readily objectively discernable principles. For example, how does EPA determine the manner of required engagement with any particular stakeholders? How does EPA decide what constitutes an actionable "linguistic, cultural, institutional, geographic, [or] other barrier" and, where such barriers are determined to exist, whether the state's proposed approach is sufficient? What measures are needed for state programs to be adequately inclusive? These are all weighty questions that the statute does not expressly address and that EPA leaves fundamentally uncertain in its proposed rule. As a result, the proposed rule is vague, unmoored to the statute, and unless corrected, would be arbitrary and capricious. *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983).

For these reasons, "meaningful engagement" should be encouraged by EPA but cannot be a required element of approvable state CAA § 111(d) programs.

12.3 EPA does not explain the legal basis for its proposal to empower third parties to conduct remote monitoring that may trigger enforceable obligations by affected facilities.

In the original proposal, EPA presented a preliminary concept that would "take advantage of the opportunities presented by the increasing use of [advanced methane detection systems] to help identify and remediate large emission events (commonly known as "super-emitters")" (86 FR 63177). EPA sought comment on "how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event." *Id*.

As we explained at the time, API concurs with the importance of identifying and addressing large emissions events. Emissions from such events have the potential to be much greater than those from normal operations at a given facility. API shares EPA's interest in seeking to reduce the incidence of such large emissions events.

We noted in our comments that the proposed "Super Emitter Response Program" was unique in that it would be the first time under the CAA that EPA asserts authority to create regulatory obligations for affected facilities based on monitoring conducted by unaffiliated third parties. We further noted EPA did not explain the legal basis for establishing such a requirement and explained that an explanation from EPA was essential to understanding whether such a novel provision is legally viable.

Unfortunately, the Supplemental Proposal does not provide the needed explanation. That failure to explain the legal underpinnings of such a key element of the proposal violates the CAA § 307(d)(3)(C) requirement to include as part of the proposed rule "the major legal interpretations underlying the proposed rule." If not cured, it also would render the final rule arbitrary and capricious because EPA would have failed to address and explain a key factor underlying this aspect of the final rule.

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[99] It is notable that the 2022 "Inflation Reduction Act" included the most significant amendments to the CAA in decades and specifically targeted Environmental Justice concerns, yet Congress stopped short of amending CAA § 111 or the other existing substantive CAA programs to require or allow consideration of EJ. In other words, Congress expansively addressed EJ, but did so by providing copious funding to address the issue and chose not to create obligation or authority to otherwise address or consider EJ in implementing the existing CAA substantive programs.

To be sure, the Supplemental Proposal includes a lengthy discussion in the preamble called the "Statutory Basis of Super-Emitter Program" (87 FR 74752). For some four pages, EPA delves deeply into two explanations as to how it believes "the proposed super-emitter response program … fits within the EPA's authority under section 111 of the CAA." *Id*. In particular, EPA explains how the program might be justified by treating super-emitting events as an affected facility warranting a § 111 emissions standard and, alternatively, how the "super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule" (either as an added compliance assurance measure or as additional equipment leak work practices). *Id*. at 74752-4.

As for those suggestions, API disagrees with EPA's contention that it has authority to treat super-emitting events as an affected facility warranting a § 111 standard of performance. Rather, at most, EPA has the authority to consider identification of super-emitter events as "monitoring" for an affected facility. As such, super-emitters may only be regulated at facilities that already are subject to NSPS OOOOb or EG OOOOc for other reasons. In other words, if a thief hatch on an NSPS OOOOb storage vessel were left open, it could (if meeting the threshold – and subject to the legal concerns set forth below) be considered a super-emitter, and EPA could require corrective action to close the thief hatch. This would be similar for emissions above the threshold from an unlit flare or control device that is mandated by NSPS OOOOb or EG OOOOc (once applicable). However, a super-emitter cannot arise from equipment at a stationary source that is not already an affected facility.

In other words, if an aerial survey identified emissions from a thief hatch on a storage vessel that is not subject to NSPS OOOOb, and the storage vessel is not yet subject to EG OOOOc, then this cannot be a super-emitter affected facility subject to the regulations and for which an operator has to take corrective action. EPA's preamble appears to support this approach in several places, but does not specifically state this in the rule. Thus, as written, it appears that one could identify a super-emitter at a stationary source that has no affected facilities or from equipment that is not an affected facility. EPA has not justified that super-emitters – many of which are malfunctions – are or can be independently considered "affected facilities" under CAA § 111.

An in any event, nowhere in this lengthy discussion – nor in any other part of the preamble or supporting documents – does EPA explain where in the CAA it finds authority to empower third parties to submit monitoring information to an affected/designated facility that triggers regulatory obligations for the facility under the rule. The need for a legal explanation is particularly necessary here, given that this is the first time that EPA has sought to establish such a requirement under CAA § 111 or, to our knowledge, under the CAA as a whole.

We also note that EPA provides a lengthy discussion of the policy rationale that stands behind the proposed Super-Emitter Response Program, including an extensive explanation of how EPA believes that "[t]he design of the super-emitter response program ensures that the EPA will make all of the critical policy decisions and fully oversee the program." *Id*. at 74749-51. In EPA's view, "the qualified third party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications within the limited confines that EPA has authorized." *Id*. at 74750. Moreover, such notifications "originating from third parties would not represent the initiation of an enforcement action by the EPA or a delegated authority." These arguments indirectly speak to EPA's assertion of possible legal authority, but the policy rationale by itself cannot legally justify EPA's novel proposal to empower citizens to develop and submit information that triggers legal obligations for affected/designated facilities.

We lastly note that, in our comments on the original proposal, we explained that CAA § 304 expressly prescribes a role for citizens in CAA implementation by authorizing them to file civil lawsuits challenging alleged violations of, among other things, CAA § 111 emissions standards. We pointed out that Congress did not provide similar express

language in CAA § 111 or elsewhere in the CAA authorizing citizen monitoring as provided in the proposed super-emitter response program. In this context, the absence of such language should be construed as a limitation on EPA's authority to allow such monitoring and such an absence is not an implicit delegation of authority from Congress to EPA.

As a further note on the relevance of CAA § 304, that section prescribes strict criteria for obtaining injunctive relief to address alleged CAA violations – including prior notice, opportunity for the government to take the lead on an enforcement action, standing to bring an enforcement case, proof of liability, and sufficient rationale to support injunctive relief. The proposal runs counter to CAA § 304 by enabling citizens to obtain injunctive relief through the super-emitter response program (in this case, investigation, corrective action, root cause analysis, and related measures) without satisfying the procedural and substantive criteria that must be met to obtain such relief under CAA § 304.

12.4 The 100 kg/hr emissions threshold for defining a "super-emitter" is not adequately justified.

As a wholly different concern, EPA proposes to "define a super-emitter emissions event as any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater." *Id*. at 74749. While EPA provides a lengthy explanation of how that threshold was determined and why EPA believes it is appropriate, the overarching rationale is that the Agency believes that this threshold captures "very large emissions events." *Id*. Indeed, the term "super-emitter" clearly was coined to describe the intended scope of coverage.

Yet just a few months ago, when addressing essentially the same issue under Subpart W of the Greenhouse Gas Reporting Program, EPA proposed to establish a new reporting requirement for "other large release events," which EPA proposed to define as "events that release at least 250 mtCO_2e per event." 87 Fed. Reg. 36920, 36982 (June 21, 2022). In explaining its rationale for setting this threshold, EPA explains that, "[w]hile some sources covered by subpart W methodologies, such as equipment leaks, may represent ''malfunctioning'' equipment, these sources are ubiquitous across the oil and gas sector [and] are generally small." *Id*. The proposed 250 mt reporting threshold is intended to capture "large emissions events." *Id*. EPA derived the value by assessing "other emissions sources that [it] considered large." *Id*. The threshold was expressly designed to be considerably lower than the emissions rates estimated for the largest release events (e.g., Aliso Canyon or Ohio well blowouts), and compares favorably to a similar reporting requirement under Subpart Y for petroleum refinery flares. *Id*. at 36983.

Despite the obvious similarities between the proposed Subpart W large emissions event proposal and the proposed NSPS OOOOb and EG OOOOc super-emitter proposal, EPA fails to mention the Subpart W proposal when explaining in the NSPS OOOOb and EG OOOOc proposal its rationale for establishing the emissions threshold for super-emitting events. The omission is particularly striking given the significant differences between the two proposals as to what EPA believes to be a large-emitting event. For example, EPA proposes to apply a kg/hr metric in NSPS OOOOb and EG OOOOc versus an event-based metric for Subpart W. Additionally, the proposed NSPS OOOOb and EG OOOOc threshold of 100 kg/hr is facially much lower than the 250 mt per event threshold in Subpart W. The Subpart OOOOb and OOOOc proposal would define events as "super-emitting" that EPA in the Subpart W proposal dismisses as "ubiquitous" and "generally small."

Clearly, the two proposed rules are contradictory in many relevant aspects. EPA has not provided any explanation in the NSPS OOOOb and EG OOOOc original or Supplemental Proposals as to why the proposed definition of "super-emitter" makes sense in light of the proposed rules for large event release reporting under Subpart W.

Lack of such an explanation would render this aspect of the final NSPS OOOOb and EG OOOOc rule arbitrary and capricious. Moreover, even if EPA provides an explanation in the final rule, the definition of "super-emitter" is of central relevance to the Super-Emitter Response Program and, thus, failure to provide an opportunity for public notice and comment on its explanation would violate the CAA § 307(d) procedural rulemaking requirements.

12.5 EPA's proposed approach to reconciling the applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc is contrary to law and unreasonable.

In our comments on the original proposal, we noted that the proposal did not include any discussion or analysis of the complex issues surrounding the applicability of the various NSPS OOOO subparts. We pointed in particular to the complexities related to the fact that the various subparts do not completely overlap – Subpart OOOO applies only to volatile organic compounds (VOCs), Subparts OOOOa and OOOOb apply to VOCs and greenhouse gases (GHGs), and EG OOOOc applies only to GHGs. Also, the affected/designated facilities are not the same under these rules. We also highlighted the question of whether a source that is an affected facility that is regulated as a new source under an existing NSPS can also be an "existing" facility under a subsequent CAA § 111(d) rule. Another important omission was any citation or explanation/analysis by EPA of the applicable law.

The Supplemental Proposal does not resolve these issues. To be sure, EPA provides an explanation of how it believes "the proposed EG OOOOc [will] impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa." (87 FR 74716). But that explanation is fundamentally incomplete because EPA still does not provide any legal analysis explaining how or why its proposed analysis is required or allowed under the law. The full extent of EPA's legal discussion on this topic is the conclusory assertion that:

> *Under CAA section 111, a source is either new, i.e., construction, reconstruction, or modification commenced after a proposed NSPS is published in the Federal Register (CAA section 111(a)(1)), or existing, i.e., any source other than a new source (CAA section 111(a)(6)). Accordingly, any source that is not subject to the proposed NSPS OOOOb as described is an existing source subject to EG OOOOc.*

Id. at 74716.

That simple explanation does not provide sufficient detail on the key legal questions we presented in our prior comments. For example, EPA does not explain how the law requires or can be interpreted to require a source to be regulated as a "new" source under a prior NSPS and, at the same time, be regulated as an "existing" source under a subsequent CAA § 111(d) program. It is clear that EPA presumes that this is how the law works. For example, the Agency repeatedly asserts that Subpart OOOOc standards "would satisfy compliance with" previously applicable NSPS – clearly implying that both standards would apply. See *Id.* at 74716-8. But the Supplemental Proposal does not explain why this outcome (applicability of both new and existing source standards to the same affected/designated facility) must or may be prescribed under the law.

EPA's silence on this important matter is particularly pronounced because EPA has never taken the position a that previously applicable NSPS continues to apply to an affected facility that triggers the applicability of a subsequent standard. For example, VOC emissions from storage vessels are regulated under both Subpart OOOO and Subpart OOOOa. It is easily conceivable that a given storage vessel might have triggered Subpart OOOO because it was constructed one month after that standard was proposed and then subsequently triggered Subpart OOOOa because the storage vessel was modified two months after that standard was proposed. It is well understood that, in such a circumstance, the Subpart OOOO storage vessel requirements cease to apply after the corresponding

Subpart OOOOa requirements are triggered. The approach to reconciling applicability suggested in the Supplemental Proposal cannot be reconciled with EPA's historic practice.

More broadly, EPA fails in both the original and Supplemental Proposals to explain how the law must or can be construed to determine what standard applies to a given source when: (1) the source is regulated as a new source under a prior version of an NSPS (such as Subpart OOOO) and then triggers a subsequent version of that new source standard (such as Subpart OOOOa); (2) the source is regulated as a new source under an existing new source standard (such as Subpart OOOO or OOOOa) and is in existence when a subsequent Section 111(d) existing source standard is proposed (such as EG OOOOc) and subsequently take effect; and (3) a source is regulated as an existing source under a Section 111(d) standard (such as EG OOOOc) and is subsequently modified or reconstructed such that it triggers a corresponding new source standard (such as NSPS OOOOb).

In sum, EPA fails to acknowledge the complexities and ambiguities as to how the law applies to this situation and fails to provide relevant legal analysis on these points. Unless EPA corrects these problems, the final rule will be both procedurally flawed (for failure to satisfy the CAA § 307(d)(3) obligation for EPA to address in the proposed rule that major legal interpretations underlying the proposed rule and to provide an opportunity for public comment) and arbitrary and capricious (for failure to address key factors underlying applicability of the various subparts). We note the legal basis for the applicability scheme for these rules is an issue of central relevance because the scope of applicability is fundamental to proper implementation and coordination of these rules.

12.6 EPA must provide more flexibility for approving state programs.

The Supplemental Proposal includes a lengthy discussion of the approach and criteria by which EPA proposes to review and approve/disapprove state CAA § 111(d) existing source programs. We have comments and recommendations on several elements of EPA's proposed approach.

All of our comments flow from the fundamental guiding principle that EPA is required to approve state programs that satisfy CAA § 111(d) standard setting criteria and cannot approve state programs that do not meet those criteria.[100] EPA correctly sums up this principle when it states "that its authority is constrained to approving measures which comport with applicable statutory requirements" (87 FR 74826 n. 274). The problems with EPA's proposal regarding approval of state programs all are grounded in violations of this principle.

To begin, EPA exceeds its authority by seeking in many places to impose its own preferences on state programs rather than recognizing that it must approve any state program that meets the statutory criteria – even programs that include elements that EPA itself would not choose, but that objectively do meet statutory standard setting requirements. In other words, if a state program meets express statutory requirements or otherwise is grounded on a reasonable construction of statutory requirements, EPA has no choice but to approve the program.

For example, EPA repeatedly and wrongly asserts that its "presumptive standards" must be used to judge the adequacy of state programs. See, e.g., *Id*. at 74812 ("a state program must establish standards of performance that are in the same form as the presumptive standards"); *Id*. ("EPA is also proposing to interpret CAA section 111 to authorize states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards"). Using EPA's presumptive standards as a measure of acceptability is wrong because a state's obligation under CAA § 111(d) is to establish standards of performance based on BSER.

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[100] The only other state obligation is to satisfy the nominal procedural requirements that EPA establishes for submission, review, and approval of state CAA § 111(d) programs.

CAA §§ 111(a)(1) and (d)(1). EPA's "presumptive standards" do not constitute BSER. Rather, they represent EPA's notion of what emissions standard might reasonably satisfy EPA's BSER determinations. But the statute unambiguously provides that states have authority and responsibility to fashion a standard that meets BSER and is not limited to the "presumptive standard" that EPA thinks is best.

Notably, EPA clearly understands that is what the statute requires. EPA itself states that "Section 111(d) does not, by its terms, preclude states from having flexibility in determining which measures will best achieve compliance with the EPA's emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion" (87 FR 74812). EPA's acknowledgment that it is the states' obligation to determine what measures "best" satisfy EPA's BSER determination is a correct statement of the law and contradicts the idea that EPA gets to decide what is "best" and impose that judgment on the states.

On a related note, EPA here indicates its commitment to faithfully implementing the "framework of cooperative federalism that CAA section 111(d) establishes," which necessarily requires EPA to defer to (and approve) state measures that satisfy the law, even when such measures do not satisfy EPA's own preferences. See also *Id*. at 74826 (EPA proposing to defer to the state's discretion to impose more costly controls). Yet on the other hand, a primary rationale for the proposed prescriptive measures for reviewing and approving/denying state programs is concern about inconsistency from state to state (e.g., *id*. at 74818 ("two states could consider RULOF for two identically situated designated facilities and apply completely different standards of performance on the basis of the same factors")) and the possibility that certain state programs will be less stringent than EPA believes they should be (e.g., *id*. at 74817 (lack of a clear framework might allow states to "set less stringent standards that could effectively undermine the overall presumptive level of stringency envisioned by the EPA's BSER determination and render it meaningless")). EPA cannot have it both ways – i.e., support state flexibility when it promotes EPA's preferred outcomes and discourage state flexibility when needed to achieve such outcomes. Such an inconsistent approach is facially arbitrary. It is easily resolved by allowing the state flexibility that EPA acknowledges to exist and, in any event, that is demanded by the statute.

Another flaw in EPA's approach is its proposal to give substantive meaning to the statutory obligation that it must approve state plans that are "satisfactory." CAA § 111(d)(2)(A). For example, EPA explains that "it is the EPA's responsibility to determine whether a state plan is "satisfactory" (87 FR 74818). EPA further explains that "the most reasonable interpretation of a ''satisfactory plan'' is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d)." *Id*. See also *id*. at 74824 ("CAA section 111(d)(2)'s requirement that the EPA determine whether a state plan is ''satisfactory'' applies to such plan's consideration of RULOF in applying a standard of performance to a particular facility. Accordingly, the EPA must determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives.").

So, by EPA's reasoning, all elements of its CAA § 111(d) implementing regulations become mandatory state obligations because, if a state does not in EPA's eyes satisfy the regulations, the state program is not "satisfactory" to EPA. Similarly, EPA gets to decide whether a state plan is "satisfactory" based on EPA's judgment as to whether the plan meets EPA's conception of the "overall health and welfare objectives" of CAA § 111(d). In other words, EPA uses the term "satisfactory" to bootstrap its own policy and legal preferences into mandatory approvability criteria.

EPA's interpretation is inconsistent with the plain words of the statute and, in any event, unreasonably expands EPA's authority to prescribe or prohibit particular outcomes under state CAA § 111(d) programs. The statute

simply says that state plans must be "satisfactory." The word "satisfactory" naturally connotes that EPA must approve any state plan that meets the statutory standard setting criteria and that otherwise meet the nominal procedural rules that EPA is required to establish to guide submission and review/approval of state plans. The word "satisfactory" does not reasonably confer upon EPA the authority to demand particular outcomes (e.g., meeting EPA's self-determined "health and welfare objectives") or to impose substantive constraints not otherwise specified by CAA § 111(d). EPA's effort to give more meaning to the word "satisfactory" is inconsistent with the law and a misplaced effort to expand the Agency's authority under CAA § 111(d).

Lastly, EPA explains that when a state decides to establish a standard of performance based on consideration of remaining useful life and other factors, it must "determine and include, as part of the plan submission, a source-specific BSER for the designated facility" (87 FR 74821). EPA then prescribes criteria that the state must follow in determining BSER and setting a corresponding emissions standard. *Id*. This is the first time in this rulemaking (and, to our knowledge, the first time ever) that EPA has interpreted the statute as authorizing and requiring a state to conduct a BSER analysis under CAA § 111(d) rather than setting standards of performance based on an EPA BSER determination.

We agree with EPA that, when a state considers RULOF in setting emissions standards for a particular source or group of sources, it necessarily must conduct a BSER analysis as part of its analysis. When a state considers RULOF, EPA's own BSER analysis ceases to have meaning because fundamental elements of that analysis – such as the cost assessment and determination that a particular emissions control method is feasible or has been adequately demonstrated – cease to apply to the source(s) covered by the state RULOF analysis.

EPA asserts that "the statute requires the EPA to determine the BSER by considering control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating: (1) The cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology" and that "a state must also consider all these factors in applying RULOF for that source." *Id*. We agree that the statute requires the first three criteria to be considered in determining BSER. We agree that application of these criteria is consistent with the principle that state CAA § 111(d) plans must meet the statutory standard setting criteria. We do not agree that the statute specifies or requires that BSER also must be based on an assessment of "the amount of reductions" or "advancement of technology." A state has the discretion to consider these factors, but EPA cannot impose these factors on a state because the statute itself does not require that they be considered.

EPA goes on to assert that a state BSER analysis "must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG using the five criteria noted above." *Id*. We disagree. The state clearly must determine BSER based on the express statutory criteria. But the law does not require a state BSER analysis to "identify all control technologies available for the source," "use the same metrics," or provide an evaluation "in the same manner" as EPA used in developing its BSER analysis. These may represent EPA's preferred method of determining BSER, but nothing in the law requires a state to follow EPA's preferred method or authorizes EPA to reject a state standard that is based on a BSER determination that employs a different approach than EPA's.

12.7 EPA does not have authority to approve more stringent state programs that are based on consideration of remaining useful life and other factors.

In the original proposal, EPA offered an extensive explanation of why it now believes it has authority to approve state § 111(d) programs that are more stringent than would be required by application of the BSER determined by

EPA. That position is expanded in the Supplemental Proposal by EPA's assertion that "states may consider RULOF to include more stringent standards of performance in their state plans" (87 FR 74825). This position represents a complete reversal of the current Subpart B provision limiting application of "RULOF" to establishing less stringent measures (See 86 FR 63251).

EPA now asserts that the term "other factors" is ambiguous and that EPA "may reasonably interpret[] this phrase as authorizing states to consider other factors in exercising their discretion to apply a more stringent standard to a particular source" (87 FR 74825). Moreover, EPA now rejects the idea that the § 111(d) Subpart B variance provisions are relevant in interpreting the scope of the Agency's authority to approve more stringent standards based on consideration of RULOF. *Id*. EPA also rejects its prior analysis of the legislative history on the grounds that it provides no meaningful guidance to EPA. *Id*. at 74826. Lastly, EPA argues that its new interpretation is consistent with the purposes of CAA § 111(d) – i.e., "to require emission reductions from existing sources for certain pollutants that endanger public health or welfare." *Id*.

EPA's attempt to reverse its position here is misplaced and is not supported by the law. First, as we discuss above, the term "other factors" is not a carte blanche invitation from Congress for EPA to create whatever plausibly "reasonable" new authorities or constraints it might conceive. The term "other factors" must be interpreted in context. As EPA itself explains, the term "remaining useful life … is a factor that inherently suggests a less stringent standard." *Id*. In this context, it stands to reason that Congress intended the term "other factors" to be interpreted such that "other factors" are applied in the same way (to reduce rather than increase stringency). Because the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term "other factors" must be construed in this manner.

Second, EPA's position is grounded in its assertion that states are not required "to conduct a source-specific BSER analysis for purposes of applying a more stringent standard" because "[s]o long as the standard will achieve equivalent or better emission reductions than required by EG OOOOc, the EPA believes it is appropriate to defer to the state's discretion to, e.g., choose to impose more costly controls on an individual source." *Id*. at n. 273. At the same time, EPA correctly notes that "its authority is constrained to approving measures which comport with applicable statutory requirements." *Id*. at n. 274; see also *Id*. at 74813 (EPA may not approve and thereby "federalize" state programs that apply to pollutants and/or affected facilities not covered by Subpart OOOOc).

It is inconsistent and arbitrary for EPA to assert that a state must conduct a new source-specific BSER analysis if it wants to use RULOF to establish a less stringent standard than would be required under EPA's BSER determination (see *Id.* at 74821), while a state is not similarly constrained when establishing more stringent standards. EPA's assertion that a more stringent standard does not require a BSER analysis because it "will achieve equivalent or better emissions reductions than required by EG OOOOc" cannot be squared with the requirement that alternative state measures must "comport with applicable statutory requirements" – which in this case include the unambiguous requirement that BSER and corresponding emissions standards must be demonstrated in practice and cost effective. EPA's suggestion that it may defer to (and approve) more stringent state requirements simply because they are more stringent is wrong because that approach does not ensure that the more stringent standards meet the statutory standard-setting criteria.

12.8 The proposed well closure requirements are not needed as a practical matter and mostly beyond EPA's authority as a legal matter.

In the original proposal, EPA raised in concept the possibility of setting standards "to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged

ineffectively" (86 FR 63240). We explained in our comments that emissions from abandoned wells are not as great as EPA suggests and that issues related to well closure are more appropriately addressed by the states and BLM. We also explained that, if EPA decided to move ahead with such standards, the possibility of requiring a demonstration of financial capacity should not be a part of that proposed rule given EPA has no authority under the Clean Air Act to impose a financial assurance requirement.

In the Supplemental Proposal, EPA proposes regulations governing well closures in both NSPS OOOOb and EG OOOOc (87 FR 74736). The proposed rules closely track the concept outlined in the original proposal – including a requirement for developing and submitting a well closure plan within 30 days of the cessation of production from all wells at a well site, which must describe the steps that will be taken to close the well, proof of financial assurance, and a schedule for completing the closure. *Id*. Monitoring must be conducted after closure to demonstrate that there are no emissions from the closed well. *Id*. And changes in ownership must be reported on an annual basis during the life of a well. *Id*.

In light of this proposal, we reiterate our prior argument that the CAA does not grant EPA authority to impose financial assurance requirements.[101] We add that EPA did not respond to these comments in the Supplemental Proposal. We further note that EPA did not explain the legal basis for the proposed financial assurance requirements in either the original or Supplemental Proposal. Indeed, EPA cites no legal authority and provides no legal analysis for any aspect of the proposed well closure standards. Such an explanation is needed for such a key and novel aspect of this proposed rule so that interested parties have the opportunity to formulate and submit comments on EPA's legal rationale. CAA § 307(d)(3). The final rule will be procedurally deficient if EPA does not cure this problem.

Lastly, EPA provides little new evidence or arguments in the Supplemental Proposal as to why well closure standards are warranted. EPA appears to rely on the more extensive discussion provided in the original proposal. Notably, that discussion focuses on "abandoned wells" (i.e., "oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells") "that are not plugged or are plugged ineffectively." (86 FR 63240). The discussion particularly targets "orphan wells" – i.e., those that have been abandoned and for which "there is no responsible owner." *Id*. EPA explains that the proposed well closure standards constitute a "potential strateg[y] to reduce emissions from these sources." *Id*. at 63241.

EPA explains in passing that states and other federal government agencies regulate well closures and have programs to address abandoned and orphan wells. Yet EPA does not conduct an in-depth assessment of these programs or make any attempt to distinguish how much of the perceived problem with abandoned or orphan wells relates to wells that pre-date the current federal and state programs versus wells that are regulated by such programs. In other words, EPA asserts that well closure standards are needed to address the problem of emissions from abandoned or orphan wells but does not determine that current state and federal programs are somehow deficient and, therefore, need to be supplemented by EPA standards going forward.

If EPA had delved more deeply into the current state of affairs, it would have seen that industry, states, and other federal government agencies are making great progress in addressing abandoned and orphaned wells. For example, the federal Bureau of Land Management highlights on its website its extensive regulatory and non-regulatory efforts to address orphan wells, including the hundreds of millions of dollars allocated by Congress in

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[101] Comment 10.1.1 on page 40 in EPA-HQ-OAR-2021-0317-0808

the recent “Bipartisan Infrastructure Law” to support tribal, state, and federal efforts in this area. EPA does not even mention the Bipartisan Infrastructure Law in the original or Supplemental Proposals.

Before finalizing the proposed well closure standards, EPA needs to consider more closely the current regulatory landscape, the extensive non-regulatory measures focused on abandoned and orphaned wells, and the expansive voluntary efforts by industry to address this important issue. Those factors are critical to understanding whether EPA rules are needed and, if so, how they should be designed and implemented.

12.9 The Supplemental Proposal would impose unreasonable, impractical, and unduly burdensome certification requirements.

The applicability of several elements of the proposed rule depends on a certification of technical infeasibility that must be executed by a professional engineer or other qualified individual. Examples include the use of an emissions control device to handle associated gas (see, e.g., proposed § 60.5377b(b)(2)), the continued use of pneumatic pumps driven by natural gas (see, e.g., § 60.5393b(c)), and the use of emitting gas well unloading methods (see, e.g., §60.5376b(c)(2)(ii)(B)(2)). EPA imposes these certification requirements out of concern about the possible “abuse” of these provisions such that they might open a “loophole” in the regulations (87 FR 74776). EPA stresses that it, “wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties.” *Id*. Thus, the proposal raises the serious prospect of individual, personal liability, not only for fraudulent certification, but also for technically erroneous (i.e., “significantly flawed”) certifications.

As we discussed in our comments on the original proposal, we support these opt out provisions as a practical matter. We agree that non-emitting measures and methods should be used where they are technically feasible and cost effective. But EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. The proposed alternative measures are a common-sense solution.

But our comments on the original proposal also expressed the concern that EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating opt outs. We pointed out that the need to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA §111 because non-emitting standards are not “adequately demonstrated” if opt outs are needed to make them feasible and workable.

We reiterate those concerns about the legal basis for EPA’s opt-out approach because onerous and potentially punitive certification requirements make the opt out approach even more legally tenuous. To begin, such certification requirements will significantly limit the situations where an opt out can be employed. As a result, what otherwise might be a reasonably viable alternative to an unworkable zero-emissions standard is unnecessarily complicated by strict certification requirements tied to an undefined standard that will be difficult to apply and limit the usefulness of the alternative. That heightens the concern that creating an opt out is unlawful circumvention of the obligation to demonstrate that BSER and the corresponding standards of performance are adequately demonstrated and cost effective.

Moreover, the proposed certification requirements are unreasonably onerous because, in each case, the certifying individual must essentially prove a negative – that the otherwise applicable zero-emissions approaches

are “technically infeasible.” There is no definition of technical infeasibility in the proposed rules, but the words could be construed as setting an exceedingly high bar, such that a given non-emitting technique is “infeasible” based solely on a technical assessment of whether it can theoretically be physically applied in the given situation. So, for example, that might require a non-emitting technology to be applied because it is technically theoretically possible, even though it would be inordinately expensive. This outcome would not be lawful because it would violate the statutory requirement that BSER and the corresponding standard of performance must be cost effective.

And, in any event, a “technical infeasibility” standard allows for second guessing by regulators or citizen enforcers, which invites a “battle of the experts” in potential enforcement actions. All of this diminishes the possibility that the opts outs can be implemented with reasonable certainty.

Lastly, the express threat of possible personal liability on the part of certifiers surely will limit the number of individuals willing to make the needed certifications, particularly in light of the uncertainties described above about what will be needed as a practical matter to demonstrate “technical infeasibility.” The clear opportunity and possibility of second guessing will be further material disincentives.

We provide here three recommended solutions to these problems. First, rather than creating opt outs that require case-specific certification, EPA should establish the opt outs in the final regulation as regulatory alternatives that may be employed if specified criteria in the rule are met. This is the usual method of prescribing standards of performance and regulatory compliance alternatives, and it would not be difficult for EPA to structure the rule in this fashion.

Second, as explained above, one of the legal flaws in EPA’s opt-out scheme is that technical feasibility is the only governing criterion. The cost of implementing the default zero-emitting standard is not a consideration. As a result, the proposed opt-out approach unlawfully evades the obligation that cost must be considered in prescribing CAA § 111 standards of performance. This flaw is easily cured by including cost as a consideration in implementing the opt-out provisions.

Third, if EPA retains the requirement for case-specific certifications, EPA should revise the required certification. The proposed regulatory text of each certification includes the following sentence: “Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.” See, e.g., § 60.5377b(b)(2). This should be revised to specify that the certification is based on “reasonably inquiry,” as is required for certifications under the Title V operating permit program. The revised certification could read as follows: “Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, ….” A “reasonable inquiry” standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

12.10 EPA should not define and impose practical enforceability requirements without first developing a consistent approach for all EPA programs.

In the original proposal, EPA proposed “to include a definition for a ‘legally and practicably enforceable limit’ as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules” (86 FR 63201). EPA explained that “[t]he intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected

facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy." *Id*.

In our comments on that proposal, we urged EPA to defer final action on the proposed definition until such time as the Agency undertakes a broad-based rule that would provide a single, consistent approach across all affected CAA programs. Such an approach would prevent potential inconsistencies among the various CAA programs (e.g., an effective emissions limit used to avoid major New Source Review (NSR) permitting might, at the same time, not be effective for purposes of the OOOOb and/or EG OOOOc storage vessel standards); would avoid the possible implication that the "effectiveness" criteria established under EG OOOOc should be applied under other CAA programs (i.e., how can an emission limit be both effective and not effective at the same time), and allow EPA to establish reasonable transition rules so that affected sources and states have time to revise existing emissions limitations as needed to meet the new effectiveness criteria.

In addition, few existing sources have express emissions limitations for methane or GHGs. Yet, EPA has newly proposed a 20 tpy methane applicability trigger for the Subpart OOOOb and OOOOc storage vessel standards (in addition to the 6 tpy VOC trigger) (87 FR 74800). As a result, many potentially affected/designated facilities likely will seek to rely on VOC emissions limitations as a surrogate for methane emissions. The use of surrogates in establishing effective potential to emit (PTE) limits is another cross-cutting issue for which EPA should establish a unitary CAA approach rather than the proposed piecemeal, rule-by-rule approach.

We raise these issues again because EPA recently announced its intention to issue national guidance on establishing effective limits on potential to emit.[102] That effort appears to be driven by a July 2021 report from the EPA Inspector General that criticized the Office of Air and Radiation for not responding to a series of 1990's era D.C. Circuit decision that vacated or remanded the then "federal enforceability" criteria that applied across EPA's CAA regulatory programs.[103] EPA intends to issue national guidance by October 2023.

EPA's announced plan to establish national rules for effective limits on PTE and to do so in the relative near future lends strong additional support to our request that EPA should not address these issues in a premature and piecemeal fashion in the EG OOOOc rule.

13.0 Other General Comments

13.1 Due to the unreasonably short duration of the comment period for the Supplemental Proposal, API has been unable to respond to all of EPA's comment solicitations.

The proposed NSPS OOOOb and EG OOOOc are both complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, many stakeholders requested an extension of the comment period in order to provide the agency with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. Concurrent with this rulemaking there are additional and overlapping regulatory developments on this subject matter including the Inflation Reduction Act Methane Emissions Reduction Program, EPA's Redesignation of Portions of the Permian Basin for the 2015 Ozone

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[102] *NAAQS, Regional Haze & Permit Program Implementation Updates*, Presentation by Scott Mathias, Director Air Quality Policy Division, OAQPS, to AAPCA Fall Meeting (Sept. 29, 2022).

[103] *EPA Should Conduct More Oversight of Synthetic-Minor-Source Permitting to Assure Permits Adhere to EPA Guidance, Report No. 21-P-0175*, memorandum from Sean W. O'Donnell to Joseph Goffman (July 8, 2021) at 17.

National Ambient Air Quality Standards, EPA's Proposed Updates to the National Ambient Air Quality Standards for PM and the Bureau of Land Management's proposed Waste Prevention Rule that all must be reviewed in accordance with the overlapping aspects of these various actions.

To provide a complete set of comments on a rulemaking as broad, impactful, precedent setting, and complex as proposed within NSPS OOOOb and EG OOOOc, API requested an additional 60 days to gather information and submit comments. Not only did EPA decline API's and other stakeholders' reasonable request for a 60-day extension of the comment period, EPA did not grant even an additional two weeks as the Agency did for the initial proposal[104], which was smaller than the Supplemental Proposal. As we have stated in Comment 12.1*,* we recognize that every administration has the right to set and implement its regulatory agenda. Nevertheless, that this Administration would expedite issuance of the original proposed rule to align with COP26[105], delay issuance of the Supplemental Proposal to align with COP27[106], and then deny the request of pertinent stakeholders to have adequate time to provide fully-informed feedback to EPA, undermines this Administration's stated goals of reducing emissions in the service of political optics. API has developed as complete a set of comments provided herein as time has allowed. However, much of the information EPA requested, as well as additional information API wanted to provide, is not included herein due to the arbitrary and unnecessarily imposed timing constraints of the comment period for the Supplemental Proposal. We restate our industry's shared goal with EPA of reducing emissions from oil and natural gas operations across the value chain. We remain concerned that this Administration will rush to the completion of a final rule that is not cost-effective, technically feasible, or legally sound. We strongly encourage EPA to adopt the recommendations in our comments to enable the final rule to meet these critically important criteria.

13.2 EPA should reduce burden associated with the collective recordkeeping and reporting requirements.

Proposed NSPS OOOOb and EG OOOOc include onerous recordkeeping and reporting that exceed typical levels of compliance assurance and are a significant cost to operators to track and maintain. EPA should continue to focus on having operators track the most necessary information to obtain assurance.

In this proposal,

- EPA increased the recordkeeping and reporting requirements without adequately justifying increased costs with respect to the administrative burden these proposed changes would require, including numerous technical demonstrations and engineering statements. Increased costs associated with administrative burden are disproportional to benefit – because benefit is marginal when compared to other mechanisms that are already in place and proposed elsewhere in this rulemaking that focus on necessary information to assist in ensuring compliance.
- EPA continues to ignore the scale of affected/designated facilities that will become subject to these provisions over time, which is well over the tens of thousands.
- EPA has included reporting requirements that are outside the Agency's jurisdiction in requiring details on well ownership transfers.

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[104] https://www.federalregister.gov/documents/2021/12/17/2021-27312/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for

[105] https://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health

[106] https://www.epa.gov/newsreleases/biden-harris-administration-strengthens-proposal-cut-methane-pollution-protect

API recognizes that it is appropriate to maintain sufficient records to demonstrate compliance. However, it is API's view that it is excessive to require such a significant level of detail to be both documented and submitted for all of the affected/designated facilities in this proposal. EPA should simplify the recordkeeping and reporting requirements to those that assure compliance without additional administrative burden. Only elements needed for compliance assurance should be requested within the annual report as supporting records retained by companies can be made available upon request from the Agency.

API has provided some initial comments on certain recordkeeping and reporting aspects of proposed NSPS OOOOb and EG OOOOc throughout this comment letter, but due to the short comment period have not had adequate time to fully assess the impact of what EPA has proposed. Some initial thoughts on the proposed draft reporting form template include the following:

- One initial concern is that many companies do not allow the use of workbooks containing macros as a cybersecurity measure and the current draft workbook contains macros. If the form is dependent on the macro formatting, this may be an issue for some reporters using the form.
- We do not support the reporting of additional information related to well transfers (including name, phone number, email, and mailing address) as proposed §60.5420b(b)(1)(v).
- The control device and closed vent system tabs are set up where multiple affected facilities that route to a single control device or through the same closed vent system cannot be identified on a single row. This will result in redundant and duplicate information being reported.
- Certain selection options for "Deviation Category" the "Description of Deviation" and "Type of Deviation" cells are automatically blacked out and do not allow an operator to provide additional context. The operator should have the ability to add free text in these areas and provide additional information as needed.

We will continue to review the recordkeeping and reporting requirements proposed within these rules along with the draft reporting form (EPA-HQ-OAR-2021-0317-1536_content) and continue to provide EPA feedback on ways to streamline the template.

13.2.1 CEDRI System Concerns

Our members have concerns with the practical implications with reporting through CEDRI when/if there is a system outage. Specifically, we request EPA evaluate the following language as proposed under NSPS OOOOb and EG OOOOc, but note these concerns also apply to NSPS OOOOa:

- §60.5420b(e)(2): We believe this paragraph should be removed or, at a minimum, be inclusive of the compliance end period and the compliance submittal date. Staff scheduling submittal may choose to do so prior to 5 days before the compliance submittal date. If EPA is requiring the use of the reporting form within CEDRI, then it should not be in deviation on the operator in any circumstance.

- §60.5420b(e)(4): The requirement for the reporter to notify EPA immediately upon discovery of an outage is unduly burdensome for the reporter. EPA should manage the reporting system and notify registered users of an outage.

- §60.5420b(e)(5)(iii): It is unclear what EPA is intending for a reporter to include as far as "a description of measure taken to minimize the delay in reporting". EPA should be taking action to minimize the delay in reporting if there is a CEDRI system outage. The regulated entity has no additional recourse in this instance.

- §60.5420b(e)(6): System outage should warrant automatic claims to those submitting reports. Operators should not be penalized when the only method for submittal is not available and out of their control.

- EPA should implement a secure process, similar to EPA's e-GGRT program, to prevent those who are not owners or operators or are authorized representatives of an affected facility from submitting to CEDRI for any affected facility.

13.3 EPA should clarify its statements regarding the Crude Oil and Natural Gas source category and the extent of crude oil operations for purposes of this rulemaking.

Within proposed NSPS OOOOb and EG OOOOc the Crude Oil and Natural Gas source category is defined consistent with historical definitions finalized in NSPS OOOO and NSPS OOOOa:

> *Crude oil and natural gas source category means:*
>
> > *(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and*
> > *(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.*

In footnote 301 (87 FR 74833), EPA states:

> [301] "*For purposes of the November 2021 proposal and this supplemental proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.*

We do not believe that EPA intends to regulate crude oil operations beyond the point of custody transfer from a well to a transmission pipeline and we request that EPA clarify and correct these statements in the final rule to align with the definition of the source category as proposed.

13.4 Applicability for Inactive sites and Reactivation of Inactive Sites

Many sites may periodically shut-in or depressurize all or partial equipment, where the entire site might be inactive or certain equipment might be inactive. We believe this is an appropriate criterion for exemption for all affected or designated facilities under NSPS OOOOb and EG OOOOc. At a minimum, we seek clarification as the status of inactive facilities and depressurized equipment as they pertain specifically to fugitive emission monitoring (Comment 2.5) and the retrofit of pneumatic controller and pneumatic pump provisions under EG OOOOc. We do not believe it is EPA's intent to require facilities that are not in active operations to retrofit the pneumatic controllers at the facility to non-emitting nor would it be appropriate for equipment that has been depressurized and inactive to be screened for fugitive emission monitoring.

Additionally, some inactive sites or equipment might be put back into service, where the applicability under NSPS OOOOb versus EG OOOOc must be delineated. One example is under *Pennsylvania's § 127.11a. Reactivation of sources*, which allows: *"a source which has been out of operation or production for at least 1 year but less than or equal to 5 years may be reactivated and will not be considered a new source if the following conditions are satisfied…".* EPA already has included language addressing this concept as it pertains to storage vessels. We

believe EPA should extend this concept to all affected and designated facilities. If a site that was inactive were to become active, there should be adequate time for the site to comply with the provisions within EG OOOOc.

13.5 The Social Cost of Greenhouse Gases

API shares the Administration's goal of reducing economy wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the EPA's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

In Attachment B, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine provided to the IWG.

13.6 Cross Reference and other Minor Clarifications

Below are some cross reference and other typos we have identified within the prosed NSPS OOOOb and EG OOOOc regulatory text.

- Subpart OOOOc makes eight references to a §60.5933c, one of which gives its title as "Alternative Means of Emissions Limitation." However, there is no actual section in EG OOOOc with that number or title.
- §60.5413b(d)(11)(iii): *A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC and methane (if applicable) required under this subpart.*
- §60.5370b(a)(1)(iii) refers to §60.5385b(a)(3), which does not appear to exist.
- The additional citations should be checked for correct cross referencing: §60.5420b(c)(2)(ii)(B), §60.5410b(f)(2)(iv)(B), §60.5420b(b)(10)(vi), and §60.5420b(c)(12).

Attachment A

Responses to EPA Solicited Comments for Use of Optical Gas Imaging in Leak Detection

Responses to EPA Solicited Comments for Use of Optical Gas Imaging (OGI) in Leak Detection

VI.C OGI Monitoring Requirements – Specifying Dwell Time to Account for Scene Complexity

[T]he EPA is soliciting comment on how dwell time could be based on the scene while still accounting for the differences in the complexity of scenes or ways to create bins for “simple” and “complex” scenes.

Response: *The most intuitive method to differentiate between “simple” and “complex” scenes would be to base it on the number of components being imaged and viewing distance. An example of a “simple” scene would be a scene of 20-25 components viewed at a distance of < 15-25 feet. This approach offers a high probability of leak detection by a technician. The high probability of detection is supported by existing operating envelope testing conducted by camera manufacturers which demonstrated consistent image detection at these distances at delta-T as low as 2 degrees C. Moreover, the number of components being limited to 25 in a simple scene means a technician is likely to have great discernment or granularity of the image which improves their ability to detect image of a leak. “Complex” scenes would be when there are greater than 25 components or viewing distances greater than 25 feet.*

VI.C OGI Monitoring Requirements – Ensuring OGI Camera Operators Survey a Scene is Adequate Without Specifying Dwell Time

The EPA is also soliciting comment on ways to similarly achieve the goal of ensuring that OGI camera operators survey a scene for an adequate amount of time to ensure there are no leaks from any components in the field of view without specifying a dwell time.

Response: *The “simple” scene criteria offered previously ensures that a technician has optimum image detection consistent with operating envelopes of camera. Specifying a dwell time for these types of scenes would be irrelevant as the technician will be looking closely at the scene in their viewfinder looking to detect any imagery. Placing a constraint of dwell time would complicate their efforts and distract from their efforts at viewing the scene. A well-trained technician who consistently passes their performance audits will be expected to make a diligent and careful survey of the components in the scene.*

VI.C OGI Camera Operators – Performance Audit Frequency

The EPA believes that it is important to verify the performance of all OGI camera operators, even the most experienced operators, on an ongoing basis. Nevertheless, the EPA is requesting comment on whether there should be a reduced performance audit frequency for certain OGI camera operators, and if so, who should qualify for a reduced frequency, what the reduced frequency should be, and the basis for the reduced frequency.

Response: *The performance audit requirements can become a significant time-consuming activity for site(s) with large numbers of technicians in their survey crew. In the initial stages of OGI monitoring implementation, more frequent performance audits have a key role to play in ensuring technician efficacy. However, technician monitoring proficiency will increase quickly over time as their monitoring experience and time doing surveys increases. The*

agency's reference to the MTEC study clearly documented this to be the case. As such, for technicians who consistently have satisfactory performance audits, it is appropriate to extend the interval between audits for those technicians. A simple methodology to do so is to follow a "skip period" approach to performance audits. For technicians who pass four consecutive quarterly performance audits, then their audit interval should be extended to semi-annual. For technicians who pass two consecutive semi-annual performance audits, then their audit interval should be extended to annual. If a technician does not pass a semi-annual or annual audit or conduct a monitoring survey during the previous 12 months per Section 10.5 of Appendix K, then quarterly performance audits would be restarted.

VI.C OGI Surveys – Length of Survey Period

[T]he EPA has heard anecdotally that this may have more to do with the number of hours the OGI camera operator has surveyed during the day, such that it is more appropriate to limit the hours of surveying per day than it is to mandate rest breaks at a set frequency. The EPA is seeking any empirical data on the topic of the necessity of rest breaks when conducting OGI surveys or the link between operator performance and length of survey period.

***Response**: Fatigue potential is directly related to duration of continuous viewing through the camera and holding the camera in viewing position for extended periods. OSHA already has appropriate guidelines for ergonomics in the work place which include eye strain etc. Sites already have rigorous guidelines and safeguards for ergonomics, heat stress, etc. EPA should not attempt to develop regulatory standards for technician rest breaks. The agency should simply state that the monitoring plan incorporate appropriate rest breaks for technicians and simply state a rest break is required if the technician has been conducting a continuous viewing through OGI camera for 20 minutes or more. It is important to note that technicians would rarely have a 20-minute continuous viewing scenario. The primary monitoring method is to survey a component or scene for 1-2 minutes and then move to next location. When moving viewing locations, the technician would lower the camera to a neutral position and not be "viewing" though camera.*

VI.C Adequate Delta-T – OGI Camera

The EPA is proposing that the monitoring plan must describe how the operator will ensure an adequate delta-T is present to view potential gaseous emissions, e.g., using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view. […] [A] commenter stated guidance should be added for operators who are using a background temperature reading in the OGI camera field of view. The EPA is requesting comment on ways that an OGI camera operator can ensure an adequate delta-T exists during monitoring surveys for cameras that do not have a built-in delta-T check function.

***Response:** The simplest and most straightforward way for a technician to ensure adequate delta-T is to utilize the camera's function to display the temperature of the equipment or background behind the component being surveyed for leaks. Most, if not all, OGI cameras in use for leak surveys have this ability currently. As such, if the technician knows the ambient temperature, then it is a simple step to add/subtract the background from ambient to determine delta-T. The elegance of this approach is it allows the technician to adjust their angles or take additional steps in*

real-time during the survey process to ensure the delta-T of the operating envelope is maintained during any survey step.

VI.C Daily OGI Camera Demonstration Prior to Imaging to Determine Maximum Distance for Imaging

[O]ne commenter suggested that instead of having different operating envelopes for different situations and having to decide which envelope to use, the OGI camera operator should conduct a daily camera demonstration each day prior to imaging to determine the maximum distance at which the OGI camera operator should image for that day. The EPA believes that this type of determination would be more difficult and costly than creating an operating envelope, as it would require OGI camera operators to have necessary gas supplies on hand and take time to do this determination daily, or potentially multiple times a day. Nevertheless, the EPA is requesting comment on this suggestion, as well as how such a demonstration could be used if conditions on the site change throughout the day, at what point would the changed conditions necessitate repeating the demonstration, and how changes in the background in different areas of the site (such as to affect the delta-T) would be factored into such a demonstration.

Response: *Use of pre-defined operating envelopes through testing as prescribed in Section 8.0 of Appendix K is a highly useful and pragmatic methodology to determine detection capability and restrictions for monitoring surveys. It is expected that most OGI camera manufacturers plan to have completed the development of the operating envelopes after Appendix K is promulgated. However, the option for a site to do a daily or site-specific distance check utilizing a known gas concentration and flow rate at actual metrological conditions prior to conducting monitoring surveys should remain an option for a site.*

The reasons for retaining an option for a daily distance check are two-fold. First, a site may be conducting monitoring surveys with an OGI camera that does not yet have established operating envelopes. This could occur for a site using an OGI camera new to market or simply that initial monitoring surveys are planned to improve emissions reductions potential prior to the manufacturer publishing operating envelopes. Second, a site may believe that monitoring conditions for a given survey or site are unique with respect to pre-defined operating envelopes and want to ensure that the guidance on delta T and distance are appropriately set for the technicians' survey task. It is logical to include this option in Appendix K.

With respect to changing conditions, technicians should already be trained in recognition of factors (e.g., meteorological conditions) which would impact the leak detection capability. When conditions are significantly different then the technicians should switch to another operating envelope or conduct another distance check verification. This is already adequately addressed in Section 9.2.3. language.

Comments for Appendix K

"Appendix K. The EPA is not including a requirement to conduct OGI monitoring according to the proposed appendix K for well sites or centralized production facilities, as was proposed in the November 2021 proposal. Instead, the EPA is proposing to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21." [FR74723]

Comment: *This is the correct decision and recognizes the fundamental differences between upstream production and other industry sectors.*

Definition of fugitive emissions component. The EPA is proposing specific revisions to the definition of fugitive emissions component that was included in the November 2021 proposal. First, the EPA is proposing to add yard piping as one of the specifically enumerated components in the definition of a fugitive emissions component. While not common, pipes can experience cracks or holes, which can lead to fugitive emissions. The EPA is proposing to include yard piping in the definition of fugitive emissions component to ensure that when fugitive emissions are found from the pipe itself the necessary repairs are completed accordingly. [FR 74723]

Comment*: Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.*

Definition of fugitive emissions component. Based on changes made and discussed under section IV.A.1.a.ii of this preamble, the EPA is proposing to define fugitive emissions component as any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and CVS not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping. [FR 74736]

Comment*: The agency has consistently set VOC and VHAP content criteria in all previous fugitive emissions component monitoring requirements. These thresholds were typically defined as "in VOC service" which specified 10% VOC as the appropriate level where the emission reduction potential from leaking components was cost-beneficial. The agency stated that no data had been offered to support a one percent methane threshold and that produced water and wastewater streams can be significant sources of emissions. In the cited reference document ''Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations.'' Final Report. California Air Resources Board. May 2020, it stated that concentrations of compounds in the liquid phase were the best prediction of expected air emissions. This is correct and makes the point of industry comment to set a definitive threshold where cost beneficial emissions can be expected. Emissions potential is directly related to the concentration of methane and/or hydrocarbon in the process stream. Small concentrations of VOC (<10 wt%) and methane do not represent significant emissions potential; a fact that the agency has recognized in multiple updates to fugitive emission regulations.*

The apparent agency approach was simply to set the threshold at a single molecule which is inconsistent with decades of regulatory approaches to fugitive emission control methodology. As the relative proportion of VOC or methane in the given component goes down, the cost effectiveness of LDAR gets increasingly less favorable until, when the amount of VOC or methane approaches zero, the cost effectiveness value approaches infinity. The agency must consider cost for BSER determination. The content threshold used within the agency's cost effectiveness analysis is unclear. Either the agency used the traditional threshold content approach for estimating the potential regulated component inventory or it has overstated the cost effectiveness through the overstatement of emissions potential from components with very small methane and VOC contents.

In the preamble, the agency stated that industry had offered no empirical data to not establish an appropriate threshold. The agency has not demonstrated why a 1% methane and 10% VOC threshold are not appropriate, or how meaningful and cost-effective emission reductions are achieved at levels below those proposed by industry. This demonstration was not met by the agency in their definition of "potential to emit" and therefore the agency has not justified their decision. The recommendation to set the definition to include the VOC threshold at 10% and methane at 1% is an appropriate good faith effort by industry to reduce emissions.

EPA proposed that where a CVS is used to route emissions from an affected facility, the owner or operator would demonstrate there are no detectable emissions (NDE) from the covers and CVS through OGI or EPA Method 21 monitoring conducted during the fugitive emissions survey. Where emissions are detected, the emissions would be considered a violation of the NDE standard and thus a deviation. [FR 74804]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. These standards mandate that closed-vent systems are monitored annually with 5/15-day repair criteria. Routine AVO monitoring rounds by unit operators is also a standard work practice. CVS piping and components have been consistently found to have low leak percentages which makes sense when one considers that most of these components remained in a fixed configuration (i.e.., car-sealed open) and there is little to no operating changes of the FECs.*

The agency proposed action to make any emissions detection a violation is also a departure from historical leak detection and repair regulatory standards. EPA stated that their logic was that the NDE requirement was an emission standard and as such it has to be a violation even if repair provisions were allowed. This is an inappropriate regulatory approach since the NDE requirement should be considered a work practice standard rather than a numerical emissions standard. The CVS and control device requirements are sufficient to ensure that NDE operating conditions are the norm. The fact that the agency has prescribed monitoring survey requirements indicates the agency knows this paradigm to be true. The most important aspect of leak detection is routine surveillance of components and piping at appropriate intervals with prompt repair to stop the leak. The current 5-15 day repair timelines achieves this fundamental precept of LDAR, and making any leak detection a violation is an unnecessary addition to the requirements that does not expedite repairs or provide environmental benefits. Violations occur when repairs are not completed per requirements and/or routine monitoring is not conducted on-time or efficaciously.

In addition to this bimonthly OGI monitoring requirement, the EPA is also proposing to require OGI monitoring of each pressure relief device after each pressure release, as it is important to ensure the pressure relief device has reseated and is not allowing emissions to vent to the atmosphere. The EPA is soliciting comment on this change from a no detectable emissions standard to a bimonthly monitoring requirement. Where the EPA Method 21 option is used, we are proposing quarterly monitoring of the pressure relief device in addition of monitoring after each pressure relief. A leak is defined as an instrument reading of 500 ppm or greater when using EPA Method 21. [FR 74807]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. The most recent and stringent precedent for PRDs is found in the Part 63 Subpart CC which*

requires monitoring post-release to verify re-seating of PRD. The agency has consistently followed this approach in other RTR evaluations which makes this approach inconsistent with agency's technical analysis.

Not requiring routine monitoring of PRDs makes sense if one considers that if PRDs are properly seated then they are assumed to be in non-venting condition. Monitoring post-release is sufficient to ensure the emission standard is maintained.

EPA is proposing a requirement to monitor the CVS at the same frequency (i.e., bimonthly OGI in accordance with appendix K or quarterly EPA Method 21) as other equipment in the process unit and to repair any leaks identified during the routine monitoring. [FR 74808]

Comment: *In existing and recently revised NSPS and NESHAP standards for closed vent systems and control devices, the agency has prescribed initial inspection and on-going annual AVO inspections. The agency indicated there would be no cost to do these surveys, but that is incorrect. The monitoring survey routes would have to be expanded to include the CVS piping/ductwork sections which increases labor costs based on increased technician field survey time.*

Appendix K

EPA is proposing to revise the scope and applicability for appendix K to remove the sector applicability and to base the applicability on being able to image most of the compounds in the gaseous emissions from the process equipment. The EPA is retaining the requirement that appendix K does not on its own apply to anyone but must be referenced by a subpart before it would apply. [FR 74837] (App K VI.B.1)

1.3 Applicability. This protocol is applicable to facilities when specified in a referencing subpart. This protocol is intended to help determine the presence and location of leaks and is not currently applicable for use in direct emission rate measurements from sources

Comment: *This change in applicability is the correct approach. However, consistent with previously submitted comments on the proposed rulemaking, we recommend EPA proceed expeditiously to amend part 63 subpart CC (RMACT 1) to allow use of OGI technology and Appendix K as an alternative to Method 21 for refineries. In the recent Refinery Sector Rulemaking, EPA proposed allowing for use of OGI as an alternative to Method 21, but did not finalize that proposal because "we have not yet proposed appendix K."*[107] *Adding OGI as an alternative to RMACT 1 would significantly reduce the refinery and Agency resources associated with preparing and reviewing Alternative Method of Emission Limitation or Alternative Monitoring requests to allow OGI for those facilities and allow refineries to take advantage of the improvements inherent in Appendix K versus the currently available leak detection and repair (LDAR) Alternative Work Practice (AWP) in Part 60 Subpart A (§60.18(g), (h) and (i)). Moreover, it would be important for EPA to amend other Part 60 and 63 standards to make Appendix K an option for industry sectors beyond refineries.*

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[107] 80 *Fed. Reg.* 75191 (December 1, 2015)

6.1.2 The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr) and either butane emissions of 5.0 g/hr or propane emissions of 18 g/hr at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less, unless the referencing subpart provides detection rates for a different compound(s) for that subpart.

Comment: *The response factor for butane and propane are almost identical, why has the agency selected lower mass rate criteria for butane? It seems inconsistent with the language in Section 1.2 which allows for the average response factor approach with respect to propane.*

9.3 The site must conduct monitoring surveys using a methodology that ensures that all the components regulated by the referencing subpart within the unit or area are monitored. This must be achieved using one of the following three approaches or a combination of these approaches. The approach(es) chosen and how the approach(es) will be implemented must be described in the monitoring plan

Comment: *The language provided in the Appendix K revisions for monitoring survey methodology provides additional flexibility consistent with industry comments. However, as written, the methodology is limited to just three options without any ability for a site to propose an alternative. Technology and survey approaches are always being improved with new creative ideas coming to forefront all the time. For example, use of GPS in surveys is only a recent capability in the past few years. The agency should add language which allows a site to use another methodology as long as it meets the intent and capabilities of the ones currently identified. A site could propose an alternative to their delegated authority prior to use*

9.4.1 For a complex scene of components, the operator must divide the scene into manageable subsections and dwell on each angle for a minimum of 2 seconds per component in the field of view (e.g., for a subsection with 5 components, the minimum dwell time would be 10 seconds). It may be necessary to reduce distance or change angles in order to reduce the number of components in the field of view

Comment: *See comments provided on "simple" and "complex" scene approaches.*

9.7.2 A full video of the monitoring survey must be recorded. The video must document the monitoring results for each piece of regulated equipment. Leaking components must be tagged for repair, and the date, time, location of each leak, and identification of the component associated with each leak must be recorded and stored with the OGI survey records.

Comment *– This language could be read to imply a full continuous video of the monitoring survey would be required which is inconsistent with the language of Section 9.7.1 where only video or still imagery of the leaks are required. This language should be deleted or clearly state that sites may elect as alternative to simply save the full continuous video versus leak imagery only.*

9.8 The monitoring plan must include a quality assurance (QA) verification video for each OGI operator at least once each monitoring day. The QA verification video must be a minimum of 5 minutes long and document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration.

***Comment** – As mentioned in previous comments to Appendix K proposals, the daily QA verification video is unlikely to offer much value to a monitoring program. The most effective methodology to ensure technician monitoring efficacy is comparative monitoring via periodic performance audits. The daily quality assurance (QA) verification video requirement should be deleted.*

10.2.2.1 A minimum of 3 survey hours with OGI where trainees observe the techniques and methods of a senior OGI camera operator (see definition in Section 3.0) who reinforces the classroom training elements.

10.2.2.2 A minimum of 12 survey hours with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and providing instruction/correction where necessary.

10.2.2.3 A minimum of 15 survey hours with OGI where the trainee performs monitoring surveys independently with a senior OGI camera operator trainer present and the senior OGI camera operator providing oversight and instruction/correction to the trainee where necessary.

***Comment:** The specific hourly requirement for each survey training phase is too restrictive and does not reflect how individuals learn and master new skills. Some technicians may need more or less time in a particular phase or benefit more from side-by-side or direct observation. A more appropriate approach is to specify a total of 30 hours of field survey hours which includes direct observation, side-by-side, and independent surveys without such prescriptive hourly content. As long as the 30 hours of training surveys includes an appropriate number of components to be surveyed (e.g., 300) and a final monitoring survey test, then the proficiency will be attained and verified.*

Attachment B

Comments on the U.S. Environmental Protection Agency's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

I. INTRODUCTION

As an addendum to our comments on the U.S. Environmental Protection Agency's ("EPA's" or "the Agency's") Supplemental Notice of Proposed Rulemaking on the revised "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" ("Proposed NSPS Revision"),[108] the American Petroleum Institute ("API") respectfully submits these additional comments on EPA's "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances" ("SC-GHG Report").[109]

API represents all segments of America's oil and natural gas industry. Our over 600 members produce, process, and distribute the majority of the nation's energy. The industry supports millions of U.S. jobs and is backed by a growing grassroots movement of millions of Americans. API was formed in 1919 as a standards-setting organization. In our first 100 years, API has developed more than 700 standards to enhance operational and environmental safety, efficiency, and sustainability. API and its members are committed to delivering solutions that reduce the risks of climate change while meeting society's growing energy needs. Addressing this dual challenge requires new approaches, new partners, new policies, and continuous innovation.

API believes that the pace of global action to reduce greenhouse gas ("GHG") emissions and effectively mitigate climate change will be determined by government policies and technology innovation. To that end, we have laid out a Climate Action Framework[110] that presents actions we are taking to accelerate technology and innovation, further mitigate GHG emissions from operations, advance cleaner fuels, drive comparable and reliable climate reporting, and, importantly, endorse a carbon price policy.

The natural gas and oil industry is essential to supporting a modern standard of living for all by ensuring that communities have access to affordable, reliable, and cleaner energy, and we are committed to working with local communities and policymakers to promote these principles across the energy sector. Our top priority remains public health and safety, and companies often have well-established policies in place for proactive community engagement and feedback aimed at fostering a culture of trust, inclusivity, and transparency. We believe that all people should be treated fairly, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

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[108] 87 Fed. Reg. 74,702 (Dec. 6, 2022).
[109] Docket ID No. EPA-HQ-OAR-2021-0317 (Sept. 2022).
[110] https://www.api.org/climate.

Indeed, API has for many years attempted to constructively engage the IWG in its development of SC-GHG estimates, and has submitted detailed comments on multiple previous IWG technical support documents, including the IWG's most recent "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" ("Interim TSD").[111] Those comments provided the IWG constructive and actionable recommendations to improve the transparency, rationality, defensibility, and thus, durability of its estimates of the SC-GHG, and urged caution on the inherently limited utility of SC-GHG estimates. Those comments also specifically recommended that the IWG publish proposals for, and accept public comment on, the recommendations the IWG was required to provide by September 1, 2021 regarding potential applications for the SC-GHG,[112] the additional recommendations the IWG was required to provide by June 1, 2022 for revising the processes and methodologies for estimating the SC-GHG,[113] and final SC-GHG estimates the IWG was supposed to publish "no later than January 2022."[114]

Insofar as API is aware, after publishing the interim SC-GHG estimates in 2021, the IWG has not completed any of the actions required by E.O. 13990 or taken any action in response to comments and recommendations submitted by API and other parties. Moreover, notwithstanding that EPA is a key participant in the IWG, EPA's unilateral development of the revised SC-GHG estimates in the SC-GHG Report is not only inconsistent with the approach President Biden committed to in E.O. 13990, it does not appear to reflect any consideration of the comments API and others provided to the IWG.

In the detailed comments that follow, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine ("National Academies" or "NASEM") provided to the IWG.

Although API appreciates EPA's willingness to accept comments on the SC-GHG Report, consistent with the National Academies' recommendations, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each modules had been updated and the SC-GHG Report had been fully drafted. Given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is insufficient for soliciting detailed feedback from informed stakeholders, particularly given that this comment period encompassed multiple holidays.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. This is a particular concern in a rulemaking conducted pursuant

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[111] 86 Fed. Reg. 24,669 (May 7, 2021).
[112] *See* 86 Fed. Reg. at 24,670.
[113] *See* E.O. 13990 at Sec. (5)(b)(ii)(D) and (E).
[114] *See* E.O. 13990 at Sec. (5)(b)(ii)(B).

to the Clean Air Act ("CAA" or "the Act") because of the CAA's enhanced requirement that EPA justify rules based solely on the record it compiles and makes public at the time of the proposal.[115]

Notwithstanding the forgoing, in Section III.b. below, API raises a number of significant technical questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. As noted therein, it is critical the SC-GHG Report completely and transparently explain the precise basis for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Finally, in Section III.c, API describes why, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. As EPA seemingly recognizes based on its apparent intent to use the SC-GHG Report in the Regulatory Impact Analysis but not as part of its assessment of the Best System of Emissions Reduction ("BSER") in the Proposed NSPS Revision itself, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.[116]

II. BACKGROUND

As noted in EPA's SC-GHG Report, the SC-GHG represents "the monetary value of future stream of net damages associated with adding one ton of that GHG to the atmosphere in a given year."[117] This metric, which originally attempted to estimate the social cost of only CO_2 emissions, "was explicitly designed for agency use pursuant to E.O. 12866. . ."[118] Since it was signed by President Clinton in 1993, E.O. 12866 has directed agencies to "propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs."[119] And when the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). Thus, the SC-GHG Report characterizes the SC-GHG as "the theoretically appropriate value to use when conducting benefit-cost analyses of policies that affect GHG emissions,"[120] and consistent with that characterization, EPA purports to only rely on the SC-GHG Report in the RIA it issued in support of the Proposed NSPS Revisions.[121]

Initially, federal agencies' consideration of CO_2 emissions in RIAs was sporadic and varied significantly between agencies.[122] When agencies did consider CO_2 emissions, they utilized a variety of different methodologies that

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[115] *See Sierra Club v. Costle*, 657 F.2d 298, 401 (D.C. Cir. 1981).

[116] *See* 87 Fed. Reg. at 74,713.

[117] SC-GHG Report at 4.

[118] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428. Per E.O. 12866 Sec. 1(a): "Federal agencies should promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling public need, such as material failures of private markets to protect or improve the health and safety of the public, the environment, or the well-being of the American people. . . . Further, in choosing among alternative regulatory approaches, agencies should select those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach."

[119] E.O. 12866 at Sec. 1(a). When the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). (E.O. 12866 at Sec. 6(a)(3)(C)). A "Significant regulatory action" is "any regulatory action that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in [E.O. 12866]" (Sec. 3(f)).

[120] SC-GHG Report at 4.

[121] *See* 87 Fed. Reg. at 74,713.

[122] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

resulted in a wide range of estimates, each with different ranges of uncertainty.[123] The government was consistent, however, in limiting use of these early estimates to RIAs, and in providing separate values for "domestic" and "global" impacts.[124] The government's consideration of CO_2 emissions became more frequent and consistent, however, after a 2008 Ninth Circuit decision remanded a fuel economy rule for failing to consider the potential benefit of CO_2 emission reductions, stating that "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero."[125] Subsequent court decisions on the necessity and method of considering CO_2 emissions for federal agency actions have been mixed.

To help federal agencies comply with E.O. 12866, "harmonize a range of different SC-CO_2 values being used across multiple Federal agencies,"[126] and "ensure consistency in how benefits are evaluated across agencies," President Obama established the IWG in 2009.[127] The IWG was tasked with developing "a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions."[128] As such, from the beginning, the IWG's SC-GHG estimates were intended to provide consistency across federal government agencies exclusively for the development of RIAs for "significant regulatory actions" involving GHG emissions. Notably, [t]his does not apply to many routine agency actions that will produce GHG emissions."[129]

The IWG's November 2013 TSD represented the first time the IWG (through OMB) accepted comment on the SC-CO_2 estimates.[130] Although the IWG and OMB had finally agreed to accept comments, they did not provide any materials other than the most recent TSDs. Thus, comments submitted by API and others urged the IWG to select its Integrated Assessment Model ("IAM") parameters through a highly transparent, collaborative, and data-driven process because modest changes to just a few model inputs drastically changes the output of the IAMs and therefore the SC-CO_2 estimate.[131]

The IWG broadly responded to the comments it received on the 2013 TSD in July 2015.[132] In that response, the IWG reiterated that the "purpose of [the IWG's] process was to ensure that agencies were using the best available information and to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions, or costs from increasing emissions, in regulatory impact analyses."[133]

The IWG updated its estimates of the SC-CO_2 again in August of 2016[134], and while API and others continued to have concerns with the transparency and rigor with which the IWG selected its model inputs, the TSD for the 2016 SC-CO_2 reflected some improvement to the characterization of uncertainty that was consistent with the NASEM Phase

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[123] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[124] Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (February 2020) ("2010 TSD) at 3.

[125] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin*., 538 F.3d 1172, 1200 (9th Cir. 2008).

[126] 2021 TSD at 10.

[127] 2010 TSD at 4.

[128] 2010 TSD at 5.

[129] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[130] OMB's first-ever solicitation of public comment on the SC-CO_2 estimates was likely in response to a September 4, 2013 multi-association Petition for Correction filed under the Information Quality Act ("IQA") and numerous demands from Congress and other stakeholders for increasing the transparency of the SC-CO_2 estimation process.

[131] *See* multi-association comments filed February 26, 2014 (OMB-2013-0007-0140). OMB's July 2015 Response to Comments did not provide the key information sought by API and others, and resisted recommendations that the IWG select these parameters through a transparent process subject to peer review. (*See* July 2015 Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.) To its credit, however, OMB requested feedback from the NASEM on the IWG's process for updating the estimates of the SC-CO_2. (*See* NASEM 2017 at 1).

[132] Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (July 2015) ("2015 RTC").

[133] 2015 RTC at 3.

[134] 2016a TSD.

1 Report,[135] as well as API's prior comments. Notably, in an addendum to the 2016 TSD, the IWG adapted its SC-CO_2 methodology to estimate social costs for methane and nitrous oxide for the first time.[136] While the 2016 TSD represented the first time the IWG provided estimates of non-CO_2 GHG emissions, the IWG continued to represent that the purpose of the estimates was to allow agencies to consistently "incorporate the social benefits of reducing . . . emissions into cost-benefit analyses of regulatory actions."[137]

Months later, President Trump disbanded the IWG and instead directed each agency to develop their own SC-GHG estimates using the same IAMs and the IWG's same overall methodology for estimating the SC-GHGs.[138] As the U.S. Department of Justice explained in its June 4, 2021 brief in opposition to several states' motion to preliminarily enjoin Section 5 of E.O. 13990, and the interim SC-GHG values published under E.O. 13990:

> Although the Trump Administration's policy approach to climate issues differed in many ways from that of the preceding administration, it continued to use standardized estimates of the social costs of greenhouse gases. Pursuant to E.O. 13783, EPA developed interim SC-CO_2 estimates by making two (*and only two*) changes to the Working Group's 2016 estimates: First, it began reporting estimates that attempted to capture only the domestic impacts of climate change, and second, it applied 3% and 7% discount rates. . . . Accordingly, although the Working Group had been disbanded, and although the estimates of the social costs of greenhouse gas estimates were now lower (because of higher discount rates and an exclusive focus on U.S.-domestic damages), agencies continued to estimate the social costs of greenhouse gases in their cost-benefit analyses, as ordered by the President, just as they had done in prior administrations.[139]

While these two changes[140] were seemingly modest, their impact on the SC-GHG estimates, was anything but small. When the Obama Administration conducted its RIA for the Clean Power Plan ("CPP") in 2015, it estimated social costs of $12, $40, $60, and $120 per short ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 in 2011 dollars.[141] When the Trump Administration conducted its RIA for the review of the CPP in 2017, it estimated the SC-CO_2 to be $6 per metric ton in 2020 (also in 2011 dollars) at the 3% discount rate, and $1 at the 7% rate.[142]

> Thus, in the span of just two years, the same government agency, utilizing the 'best available science' put forth estimates for the same metric that had changed by so many orders of magnitude

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[135] National Academies of Sciences, Engineering, and Medicine 2016. *Valuing Climate Damages. Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on Near-Term Update*:. Washington, DC: The National Academies Press ("NASEM 2016").

[136] Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social cost of Methane and the Social Cost of Nitrous Oxide ("2016b TSD"). OMB did not request or receive the NASEM's feedback on the new estimates of the social costs of methane and nitrous oxide, nor were they subject to notice and comment, or peer reviewed. Rather, they were premised entirely on a U.S. Environmental Protection Agency ("EPA") employee's 2015 paper, which at that point had not been reviewed or published. (*See* Martin, A.L., Kopits, E.A., Griffiths, C.W., Newbold, S.C., and A Wolverton. 2015. Incremental CH_4 and N_2O Mitigation Benefits Consistent with the U.S. Government's SC-CO_2 Estimates. *Climate Policy* 15(2): 272-298).

[137] 2016 TSD at 3.

[138] *See* Executive Order 13783 (March 28, 2017) ("E.O. 13783").[138]

[139] *Missouri v. Biden*, 4:41-cv-00287 (E.D. MO 2021) (Page 11 of Defendants' June 4, 2021 Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction) (emphasis added).

[140] These changes flowed from E.O. 13783 ("when monetizing the value of changes in greenhouse gas emissions resulting from regulations, including with respect to the consideration of domestic versus international impacts and the consideration of appropriate agencies shall ensure, to the extent permitted by law, that any such estimates are consistent with the guidance contained in OMB Circular A-4.")

[141] U.S. EPA, EPA-452/R-15-03 Regulatory Impact Analysis for the Clean Power Plan (2015) at 4-2. (The four SC-CO2 estimates differ based on use of discount rates of 5%, 3%, 2.5%, and the ninety-fifth percentile distribution at the 3% discount rate. (See 4-6, 4-7).

[142] U.S. EPA, Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal (2017) at 44. The conversion factor for metric ton to short ton is approximately 0.91, such that these estimates were actually about 9% lower when compared to the Obama-era estimates (2017 CPP RIA at 44).

as to be farcical. This was the case even though the Trump and Obama analyses utilized the same underlying models.[143]

Just a few years later, the IWG has republished the prior 2016 SC-GHG values as the new Interim SC-GHG estimates, and as instructed by E.O. 13990, these estimates "tak[e] global damages into account" and utilize discount rates that the IWG believes "reflect the interests of future generations in avoiding threats posed by climate change."[144] As a result, the Trump Administration's estimated SC-CO_2 values of $1 and $6 per metric ton in 2020 (in 2011 dollars)[145] increased to $14, $51, $76, and $152 per metric ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 (in 2020 dollars).[146]

This whipsawing of SC-GHG estimates is not based on any objective errors or omissions. Indeed, the IWG and Trump Administration can both point to academic scholarship and regulatory guidance in support of their selections of discount rates and geographic scales. Rather, these divergent estimates demonstrate the extent to which any given estimate of the SC-GHG differs based on one or two subjective judgements. The output of the models is dependent on subjective framing decisions that "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[147] And because many of the key analytical framing decisions that truly drove model output are subjective and not purely scientific determinations, robust and transparent stakeholder and public engagement is essential.

As API urged in its comments on the 2021 TSD and reiterates here, the sensitivity of SC-GHG modeling output to one or a few subjective inputs raises serious questions of the SC-GHG estimates' reliability and utility in rulemaking and policy analyses. It also illustrates the profound importance of adopting analytical framing decisions through a structured and predictable process that is open, transparent, and data-driven. While EPA may have valid reasons for unilaterally developing its own SC-GHG estimates, API is concerned that this unexplained deviation from the SC-GHG estimation and updating process that was historically consigned and recently re-entrusted to the IWG reflects another *ad hoc* estimation approach that lacks the necessary structure, consistency, and transparency.

Moreover, given that EPA's SC-GHG Report contains the most recent estimate of the SC-GHG provided by the federal government, API is concerned that other federal agencies may opt to rely on the estimates in the EPA's SC-GHG Report rather than the estimates in the IWG's 2021 Interim TSD. While this concern is somewhat mitigated by E.O. 13990's requirement that agencies use the IWG's values, the absence of any clear statement from EPA as to what the SC-GHG Report is or how its estimates are to be used perpetuates a serious concern that EPA's values may be misapplied in a variety of different regulatory and administrative contexts.

III. DETAILED COMMENTS

API is concerned about the procedures EPA employed when developing the SC-GHG Report and the revised estimates contained therein. We also have substantive technical questions and concerns about the methodology EPA employed in generating the revised SC-GHG estimates and the manner in which the Agency presented its

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[143] Taylor, A. (2018). Why the social cost of carbon is red herring. Tulane Environmental Law Journal, 31(2), 345-372 at 347.

[144] E.O. 13990 at Sec. 5(a) and 5(b)(iii).

[145] Using discount rates of 7% and 3%.

[146] Interim TSD at Table ES-1 (using discount rates of 5%, 3%, 2.5%, and the 95th percentile of the 3% discount rate)

[147] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 370. [T]hose who would consider inclusion of IAM-generated estimates, particularly high-dollar ones, of the SCC to be an unmitigated success should nonetheless pay heed to the crow on the shoulder: a high degree of arbitrariness is currently baked into these estimates and it is quite difficult to know the degree to which they may be relied upon for accuracy or manipulated by agencies across different administrations.

estimates in the SC-GHG Report. Finally, API believes that EPA should more fully and explicitly explain why the inherent limits of the SC-GHG estimates render them unsuitable for agency rulemaking and decisions that require the SC-GHG to be expressed as a single value or within a reasonably narrow range of uncertainty. The subsections that follow discuss each of these three broad areas of concern in detail.

a. **Procedural Concerns**

As President Biden noted in Executive Order 13990 ("E.O. 13990") on his first day in office, "[a]n accurate social cost is essential for agencies to accurately determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses . . ."[148] To that end, E.O. 13990 further instructed that, in undertaking actions such as developing SC-GHG estimates, "the Federal Government must be guided by the best science and be protected by processes that ensure the integrity of Federal decision-making.[149] Consistent with that mandate, President Biden also issued a Presidential Memorandum to all heads of executive departments and agencies reaffirming the Biden Administration's commitment to the principles outlined in President Clinton's Executive Order 12866 ("E.O. 12866")[150], which established the basic foundation for executive branch review of regulations, and President Obama's Executive Order 13563 ("E.O. 13563"),[151] which "took important steps toward modernizing the regulatory review process."[152]

Thus, through the Regulatory Review Memorandum, President Biden reaffirmed his administration's commitment to "allow for public participation and an open exchange of ideas;"[153] using "best available techniques to quantify anticipated present and future benefits and costs as accurately as possible;"[154] and ensuring "the objectivity of any scientific and technological information and processes used to support . . . regulatory actions."[155]

One week later, President Biden reiterated to his executive departments and agency heads that "[i]t is the policy of my Administration to make evidence-based decisions guided by the best available science and data."[156] According to the President Biden's Scientific Integrity Memorandum, "[w]hen scientific or technological information is considered in policy decisions, it should be subjected to well-established scientific processes, including peer review where feasible and appropriate. . ."[157]

API supports the principles President Biden outlined in these Executive Orders and presidential memoranda, and believes that certain aspects of EPA's development of SC-GHG estimates, such as taking public comment and committing to peer review, are broadly consistent with these principles. In other respects, however, EPA's development of the SC-GHG Report thus far appears to be the product of an insufficiently structured and transparent process.

Indeed, EPA's SC-GHG Report represents an unexplained departure from the more structured, transparent, and collaborative interagency process that the Biden Administration promised when it encouraged stakeholders

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[148] E.O. 13990 at Sec. 5.
[149] E.O. 13990 at Sec. 1.
[150] Signed Sept. 30, 1993.
[151] Signed Jan. 18, 2011.
[152] Memorandum for the Heads of Executive Departments and Agencies regarding "Modernizing Regulatory Review" (Jan. 20, 2021) ("Regulatory Review Memorandum").
[153] E.O. 13563 at Sec. 1(a).
[154] E.O. 13563 at Sec. 1(c).
[155] E.O. 13563 at Sec. 5.
[156] "Memorandum on Restoring Trust in Government Through Scientific Integrity and Evidence-Based Policymaking" Memorandum From President Biden to the Heads of Executive Departments and Agencies (Jan. 27, 2021) ("Scientific Integrity Memorandum"). *See also* Executive Order 14007, which establishes the President's Council of Advisors on Science and Technology. (Jan. 27, 2021) ("E.O. 14007).
[157] Scientific Integrity Memorandum preamble.

interested in the SC-GHG development process to engage with the IWG. EPA's SC-GHG Report reflects no consideration of the comments API and others submitted to the IWG, and the limited data and time that EPA has provided at this stage does not appear consistent with a strong Agency interest in soliciting critical analysis. Furthermore, EPA's curious solicitation of comments on the SC-GHG Report within an NSPS rulemaking, which does not utilize the SC-GHG Report, does not particularly reflect an interest in transparency and collaboration. In fact, EPA's equivocal and fluctuating descriptions of the SC-GHG Report make it impossible for the public to even understand why EPA drafted the SC-GHG Report in the first place, or how the Agency intends to use it.

1. Lack of Clarity Regarding What the SC-GHG Report is and how it will be used

In both the preamble to the Proposed NSPS Revisions and the RIA in EPA's docket for the Proposed RIA Revisions ("Docketed RIA"), EPA concludes that the IWG's "interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science."[158] Therefore, the Agency "estimated the climate benefits of methane emission reductions expected from this proposed rule using the social cost of methane (SC-CH_4) estimates presented in the [IWG's 2021 TSD]."[159]

Having disclaimed that the RIA estimated the climate benefits of the proposal's anticipated methane reductions using only the interim SC-GHG estimates from the IWG's 2021 TSD, EPA's preamble to the Proposed NSPS Revisions then describes the SC-GHG Report as "a sensitivity analysis of the monetized climate benefits using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine."[160] According to EPA's preamble, the RIA presents the results of the SC-GHG Report's screening analysis in "Appendix B of the RIA."[161] However, the Docketed RIA does not include the sensitivity analysis EPA described in the preamble, nor does it contain any reference to, or even mention of, the SC-GHG Report.

Earlier versions of the RIA that were exchanged between and edited by EPA, OMB, and other agencies reflect that the RIA previously contained a substantial discussion of the SC-GHG Report and also included EPA's new estimates from the SC-GHG Report in a sensitivity analysis in a then-designated Appendix B.[162] These aspects of the draft RIA were deleted in their entirety without explanation shortly before publication of the Proposed NSPS Revisions. However, and particularly problematic from the perspective of transparency in public engagement as well as EPA's docket and rulemaking requirements under CAA Section 307, the version of the RIA that EPA posted on its website for public comment on November 11, 2022 contains the subsequently deleted discussion of the SC-GHG Report and Appendix B sensitivity analysis.[163] Thus, EPA is presently soliciting comments on two strikingly different versions of the Draft RIA. Indeed, while it is beyond the scope of this appendix's specific focus on EPA's SC-GHG Report, the Agency's publication of two divergent Draft RIAs raises significant questions about the sufficiency of the notice-and-comment opportunity on the required E.O. 12866 analysis as well as the Proposed NSPS Revisions.

While EPA's last minute revisions to the RIA remain unexplained, what is clear from the Docketed RIA is that EPA's SC-GHG Report is not a sensitivity analysis, and that the report's revised SC-GHG estimates are not amenable for use in sensitivity analyses. EPA's "Sensitivity and Uncertainty Analyses: Training Module" describes a "sensitivity analysis" as "a method to determine which variables, parameters, or other inputs have the most influence on the

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[158] 87 Fed. Reg. at 74,843; Docketed RIA (EPA-HQ-OAR-2021-0317-0173) at 3-6.

[159] 87 Fed. Reg. at 74,713; *See also* 87 Fed. Reg. at 74,843; *See also* the RIA in EPA's docket for the Proposed NSPS Revisions at 3-6.

[160] 87 Fed. Reg. at 74,843.

[161] 87 Fed. Reg. at 74,714, Table 5, note b; *See also* 87 Fed. Reg. at 74,843.

[162] *See* Draft RIA revisions between September and November 2021 at EPA-HQ-OAR-2021-0317-1540,1541, 1542, 1543, 1544, 1545, 1546, 1548, 1573, 1574, 1575, and 1576.

[163] *See* https://www.epa.gov/environmental-economics/scghg.

model output."[164] Consistent with this description, EPA's Training Module explains that "[t]here can be two purposes for conducting a sensitivity analysis [1] comput[ing] the effect of changes in model inputs on the outputs; [2] to study how uncertainty in a model output can be systematically apportioned to different sources of uncertainty in the model input."[165]

EPA's SC-GHG Report and the SC-GHG estimates contained therein are in no way suited to these purposes. The estimates in EPA's SC-GHG Report were derived in a manner wholly different from the IWG's SC-GHG estimates. For each of the four modules of the SC-GHG estimation process - socioeconomics and emissions, climate, damages, and discounting – EPA's SC-GHG Report uses different models, methodologies, analytical framing decisions, and data than the IWG utilized. As detailed in the Executive Summary to the SC-GHG Report:

> The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future Social Cost of Carbon Initiative . . . The climate module relies on the Finite Amplitude Impulse Response (FaIR) model… The socioeconomic projections and outputs of the climate module are used as inputs to the damage module to estimate monetized future damages from temperature changes. Based on a review of available studies and approaches to damage function estimation, the report uses three separate damage functions to form the damage module. They are: 1. a subnational-scale, sectoral damage function… 2. a country-scale, sectoral damage function… and 3. a meta-analysis-based damage function… The discounting module . . . us[es] a set of dynamic discount rates that have been calibrated following the Newell et al. (2022) approach, as applied in Rennert et al. (2022a, 2022b). … Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates. … Finally, the value of aversion to risk associated with damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. The estimation process generates nine separate distributions of estimates – the product of using three damage modules and three near-term target discount rates – of the social cost of each gas in each emissions year. To produce a range of estimates that reflects the uncertainty in the estimation exercise while providing a manageable number of estimates for policy analysis, in this report the multiple lines of evidence on damage modules are combined by averaging the results across the three damage module specifications.[166]

Every aspect of the above-described estimation process differs from the process employed by the IWG. And, because every aspect of EPA's SC-GHG estimation process differed from the IWG's process, it does not allow EPA "to determine which variables, parameters, or other inputs" in the IWG's estimation process "have the most influence on the model output." Examining two wholly different estimation processes does not provide any basis to discern how any of the IWG's inputs may impact the IWG's model output or apportion uncertainty to the IWG's various inputs.

"Sensitivity analyses" require the isolation and examination of one or a few model inputs while all other model parameters remain constant. For instance, in the 2021 TSD, the IWG advised that "agencies may consider

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[164] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).

[165] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).

[166] SC-GHG Report at 1-2.

conducting additional sensitivity analysis using discount rates below 2.5 percent."[167] Consistent with EPA's Training Module and standard practices for conducting sensitivity analyses, the IWG instructed that agencies' sensitivity analyses should isolate a single input (the discount rate) in order to assess the impact of changes from that single input on the model output.

The estimates in EPA's SC-GHG Report are simply new estimates based on new methods and data, and they therefore plainly have no value in any scientifically relevant sensitivity analysis. Indeed, what EPA deemed a "Screening Analysis" in the since-deleted sections of the Docketed RIA was not a screening analysis at all, at least as defined by EPA's Training Module. EPA merely compared the values from the IWG's 2021 TSD to EPA's SC-GHG Report and found that the benefits estimated in EPA's SC-GHG Report were higher than the IWG's 2021 interim estimates. This is truly the full extent of EPA's use of the SC-GHG Report for a "sensitivity analysis," which perhaps explains the Agency's decision to strike those references from the Docketed RIA.

Recognizing that neither EPA's SC-GHG Report nor the estimates contained therein constitute, or can credibly be used in sensitivity analyses, one is compelled to recognize the SC-GHG Report's estimates for what they are – SC-GHG values that are wholly separate and distinct from the 2021 IWG interim SC-GHG estimates that the Biden Administration directed all agencies to use. In fact, the SC-GHG Report itself never suggests its estimates are intended or even suitable for sensitivity analyses. The SC-GHG Report accurately describes them as "new estimates of the SC-GHG."[168]

Indeed, the SC-GHG Report's estimates are "new estimates of the SC-GHG," but given EPA's deletion of the supposed "sensitivity analysis" and assertion that the SC-GHG Report's estimates were not used in the RIA or the "statutory [best system of emissions reduction] determinations" in the Proposed NSPS Revisions,[169] commenters are left with no explanation why EPA developed the SC-GHG Report, how EPA intends to use the report's estimates, or why EPA included the SC-GHG Report in the docket for the Proposed NSPS Revisions. A truly transparent and collaborative process demands much more than this. EPA should provide a full and complete explanation for the development and intended use of the SC-GHG Report before subjecting it to peer review or public comment. Absent any explanation of the SC-GHG Report's intended use, reviewers have little basis to opine on its suitability.

2. Inconsistency with the Biden Administration's Stated Approach to the SC-GHG

From the earliest days of his Administration and consistently thereafter, President Biden and other Administration officials publicly committed to developing and updating government-wide SC-GHG estimates through the IWG by prescribing a detailed and incremental process. Based on the Administration's representations, API and other stakeholders devoted significant time and resources attempting to engage the IWG, but the rigorous and transparent IWG process that the Biden Administration promised has not yet materialized in any meaningful way. Now, more than two years after the IWG released its first and only publication of the several it had been charged with developing, EPA appears to be charting its own course by developing its own agency-specific SC-GHG estimates in the SC-GHG Report.

As discussed in more detail below, EPA's independent development of SC-GHG estimates is incompatible with and, in fact, undermines the unified approach promised by the Biden Administration in E.O 13990. We also describe

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[167] 2021 TSD at 4; *See also* 2021 TSD at 21 ("the IWG finds it appropriate as an interim recommendation that agencies may consider conducting additional sensitivity analysis using discount rates below 2.5%.").

[168] SC-GHG Report at 84.

[169] 87 Fed. Reg. at 74,843.

why EPA's unilateral SC-GHG estimates and any subsequent proliferation of agency-specific SC-GHG estimates contravene the Administration's stated interest in assessing the benefits and costs of proposed regulations consistently and cohesively across all federal agencies.

i. President Biden's Promised Approach for the Development and Agency use of SC-GHG Estimates

After the Trump Administration disbanded the IWG, President Biden on his first day in office issued E.O. 13990, which reestablished the IWG as the federal entity charged with developing and publishing the SC-GHG estimates that are to be used by all federal agencies.[170] The IWG's mission is fivefold:

> (A) publish an interim [SC-GHG] within 30 days of the date of this order, which agencies shall use when monetizing the value of changes in greenhouse gas emissions resulting from regulations and other relevant agency actions until final values are published;
>
> (B) publish a final [SC-GHG] by no later than January 2022;
>
> (C) provide recommendations to the President, by no later than September 1, 2021, regarding areas of decision-making, budgeting, and procurement by the Federal Government where the [SC-GHG] should be applied;
>
> (D) provide recommendations, by no later than June 1, 2022, regarding process for reviewing, and, as appropriate, updating, the [SC-GHG] to ensure that these costs are based on the best available economics and science; and
>
> (E) provide recommendations, to be published with the final [SC-GHG] under subparagraph (A) if feasible, and in any event by no later than June 1, 2022, to revise methodologies for calculating the [SC-GHG], to the extent that current methodologies do not adequately take account of climate risk, environmental justice, and intergenerational equity.[171]

Insofar as API is aware, the IWG has only completed the first of the five tasks prescribed by E.O. 13990.[172] Regarding these interim estimates, the E.O. mandates that "agencies ***shall*** use" them in promulgating their own "regulations and other relevant agency actions until final values are published."[173] Thus, although it is unclear why EPA developed the SC-GHG Report and how the Agency intends its SC-GHG estimates to be used, it bears mentioning that agencies deviating from these interim estimates do so in contravention with E.O. 13990.

The requirements of E.O. 13990 are also memorialized in the 2021 Interim TSD, which describes President Biden's directive that the reconstituted IWG "ensure that SC-GHG estimates used by the U.S. Government (USG) reflect the best available science and the recommendations of the National Academies (2017)…"[174] Consistent with the Executive Order, the IWG plainly recognized that the SC-GHG estimates it developed were to be used throughout the "U.S. Government," unless expressly precluded by statute.[175]

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[170] E.O. 13990 at Sec. 5.

[171] E.O. 13990 at Sec. 5(b)(ii).

[172] 2021 TSD.

[173] E.O. 13990 at Sec. 5(b)(ii)(a) (emphasis added).

[174] 2021 TSD at 3.

[175] Social Cost of Greenhouse Gas Emissions: Frequently Asked Questions (FAQs), ("OIRA Guidance") at 2, June 3, 2021. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/Social-Cost-of-Greenhouse-Gas-Emissions.pdf.

The IWG's Interim TSD goes on to instruct that the Interim SC-GHG estimates "should be used by agencies until a comprehensive review and update is developed in line with the requirements in E.O. 13990."[176] The Interim TSD also "determined that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates (2.5 percent, 3 percent, and 5 percent) as were used in regulatory analyses between 2010 and 2016 and subject to public comment."[177]

OMB, the entity responsible for coordinating the IWG efforts,[178] has likewise confirmed that President Biden's reconstitution of the IWG demonstrates that the President intended the IWG alone develop the SC-GHG estimates necessary "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[179] This directive is further confirmed in the June 2021 guidance document OIRA issued to agencies to assist in applying Section 5 of E.O. 13990.[180] The OIRA Guidance clarified that "[p]ursuant to E.O. 13990, when agencies prepare an assessment of the potential costs and benefits of regulatory action for purposes of compliance with E.O. 12866, they *must* use the 2021 interim estimates in monetizing increases or decreases in greenhouse gas emissions that result from regulations and other agency actions until updated values are released by the IWG."[181] Accordingly, E.O. 13990, the 2021 Interim TSD, OMB's solicitation of comments on the Interim TSD, and OIRA's guidance not only directed federal agencies to use the IWG's SC-GHG estimates, they apprised stakeholders interested in the federal government's SC-GHG estimates that the IWG was the sole entity with which to engage regarding the development of these important values.

In litigation surrounding E.O. 13990 and the 2021 Interim TSD, the U.S. Department of Justice ("DOJ") also describes the Biden Administration's stated approach to developing and using SC-GHG estimates, and opined on the degree to which E.O. 13990 compelled agencies to use the IWG's values:

> … the Executive Order requires agencies to use the Interim Estimates in some circumstances. *See* E.O. 13990 §§ 5(b)(ii)(A) (using the word "shall"); OIRA Guidance, at 1. But that directive is inoperative whenever the agency faces any conflicting statutory obligation . . .In other words, agencies will only ever rely on the Interim Estimates when they have discretion to do so…[182]

As DOJ stated elsewhere even more succinctly, "if an agency undertakes [SC-GHG] monetization, it shall use the Interim Estimates rather than another set of figures."[183]

ii. EPA's SC-GHG Report Contravenes the Approach President Biden Promised Stakeholders

Although it is not yet clear how EPA intends to use the estimates in its SC-GHG Report, the Agency's development and publication of these values appears to conflict with President Biden's explicit directive that the IWG develop the federal government's SC-GHG estimates and that federal agencies use those estimates. The Administration assigned this centralized role to the IWG "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[184] Even though EPA is a key member of the IWG and EPA's staff certainly

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[176] 2021 TSD at 4.

[177] 2021 TSD at 4.

[178] *See* E.O. 13990 at Sec. 5; *See also* 86 Fed. Reg. at 24,669.

[179] 86 Fed. Reg. at 24,669.

[180] *See* OIRA Guidance.

[181] OIRA Guidance at 1.

[182] Defendants' Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction, Page 23, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).

[183] Brief for Appellees, Page 40, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).

[184] 86 Fed. Reg. at 24,669.

have a high level of expertise in climate science and economic analysis, E.O. 13990's reestablishment of the IWG seems to indicate that the Biden Administration believed that development of the highly important SC-GHG estimates called for a breadth of expertise and diversity of opinions unlikely to be found within a single agency.

While API has often disagreed with the IWG's lack of transparency and with various modeling decisions and methodologies that the IWG has employed in developing SC-GHG estimates, we believe that the multi-agency composition of the IWG provides at least an opportunity to develop future SC-GHG estimates using a greater diversity of viewpoints and expertise. Thus, when the Biden Administration once again consigned the federal government's SC-GHG estimation process to the IWG, API once again devoted significant time and resources developing comments reflecting our own viewpoints and considerable expertise. Unfortunately, the IWG's unexplained inaction on the tasks it was assigned in E.O. 13990 along with EPA's unilateral development of SC-GHG estimates in contravention with E.O. 13990 seem to indicate that API's efforts to engage the IWG may have been in vain and that the process laid out in E.O. 13990 has been inexplicably abandoned.

API and others with a deep interest in, and credible expertise relevant to, the development of SC-GHG estimates are effectively precluded from meaningfully engaging with the federal government on these estimates if the Administration changes without explanation the entities, planned actions, and procedures for developing SC-GHG estimates.

The other reason the Administration re-established the IWG and tasked it with developing the SC-GHG estimates was "to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions in regulatory impact analyses."[185] This accords with OMB Circular A-4, which emphasizes that "[i]n undertaking [benefit-cost analysis and cost-effectiveness analysis], it is important to keep in mind the larger objective of analytical consistency in estimating benefits and costs *across regulations and agencies*, subject to statutory limitations."[186]

While we recognize that the Administration has announced its intent to revise Circular A-4,[187] the mere prospect of these revisions provides no basis for contravening the guidelines and instructions currently provided by Circular A-4. Unless and until Circular A-4 is revised or replaced, it should continue to guide EPA and other agencies to develop clear, transparently supported, objective, and consistent RIAs. Indeed, far from justifying any departures from Circular A-4's guidelines, the Administration's announcement that Circular A-4 will be revised further illustrates that EPA's unilateral development of SC-GHG estimates is inconsistent with the overall RIA and SC-GHG development framework that the Biden Administration publicly announced.

Finally, the need for a single consistent process for developing the SC-GHG estimates used in RIAs is further reflected in a 2020 Government Accountability Office ("GAO") Report on the SC-GHG and specifically the manner in which the federal government should address the recommendations of the National Academies."[188] Recognizing that the National Academies' recommended procedural and technical improvements could not be feasibly implemented by a multitude of different agencies, the GAO urged OMB to "identify a federal entity or entities to be responsible for addressing the National Academies' recommendations…"[189] GAO considered the recommendation "implemented" when E.O. 13990 reinstated the IWG.[190]

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[185] 2021 TSD at 10.

[186] OMB Circular A-4, Pages 9-10 (emphasis added).

[187] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.

[188] GAO-20-254, Report to Congressional Requesters, SOCIAL COST OF CARBON: Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis ("GAO-20-254").

[189] GAO-20-254.

[190] GAO-20-254 Recommendation Status, https://www.gao.gov/products/gao-20-254#summary_recommend.

Thus, EPA's unexplained deviation from the SC-GHG development approach laid out in E.O. 13990 not only upends the process to which API and other have devoted time and resources, it undermines the federal government's longstanding objective of making RIAs more consistent across agencies and detracts from what the GAO and this Administration identified as necessary to improve the SC-GHG estimation process consistent with the National Academies' recommendations.

3. Failure to Respond to Comments

As a further consequence of the Agency's decision to unilaterally develop its own SC-GHG estimates, EPA's SC-GHG Report does not appear to be based on any meaningful consideration of the many significant and detailed comments submitted to the IWG, including most recently, the many comments in response to the 2021 Interim TSD. Based on the Biden Administration's representation that the IWG alone would develop the SC-GHG estimates that would be used by the many agencies of the federal government, "[t]he Office of Management and Budget (OMB), on behalf of the cochairs of the Interagency Working Group on the Social Cost of Greenhouse Gases, including the Council of Economic Advisors (CEA) and the Office of Science and Technology Policy (OSTP)," requested "public comment on the interim TSD as well as on how best to incorporate the latest peer-reviewed science and economics literature in order to develop an updated set of SC–GHG estimates."[191]

Notwithstanding that the IWG purported to solicit public comments "in order to facilitate early and robust interaction with the public on this key aspect of this Administration's climate policy,"[192] neither the IWG nor EPA, which is a key member of the IWG, ever responded to or meaningfully considered the public comments submitted by API and many others in 2021. This does not represent a valid and transparent effort to engage the public and solicit feedback to improve agency decision-making.

"For an agency's decisionmaking to be rational, it must respond to significant points raised during the public comment period."[193] EPA is not relieved of this obligation simply because the comments were solicited by OMB on behalf of the IWG. As a key member of the IWG, EPA "reviewed the comments submitted to the IWG,"[194] and therefore had an obligation to "engage the arguments raised before it."[195]

The issues on which the IWG solicited comment, including advances in science and economics, approaches for implementing the National Academies' recommendations, approaches for intergenerational equity, and the use of discount rates,[196] are directly relevant to the EPA's SC-GHG Report. So too are the significant comments and data submitted by API and others in response to the IWG's solicitation.

In particular, API submitted detailed and constructive questions and comments on issues regarding the selection of discount rates, the ability to reasonably forecast impacts on expansive time horizons, and the importance of providing domestic SC-GHG values alongside global values. The IWG never responded to these comments and questions, and given the existence of these same concerns in EPA's SC-GHG Report, EPA plainly ignored API's comments as well.

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[191] 87 Fed. Reg. 24,669 (May 7, 2021).

[192] 87 Fed. Reg. at 24,670.

[193] *Allied Local & Reg'l Mfrs. Caucus v. EPA,* 215 F.3d 61, 68 (D.C. Cir. 2000).

[194] SC-GHG Report at 8.

[195] *Del. Dep't of Nat. Res. & Envtl. Control v. EPA*, 785 F.3d 1, 11 (D.C. Cir. 2015); *see Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 214 (D.C. Cir. 2013).

[196] 87 Fed. Reg. at 24,670.

It is not enough for EPA to suggest that it "has reviewed the comments submitted to the IWG in developing [the SC-GHG Report]."[197] EPA must respond in a reasoned manner to the comments received, [] explain how the agency resolved any significant problems raised by the comments, and [] show how that resolution led the agency to [its conclusion]."[198] "Consideration of comments as a matter of grace is not enough.' It must be made with a mind open to persuasion."[199]

It is also insufficient that EPA is now accepting comment on the SC-GHG Report. To begin, EPA's acceptance of comments on entirely new SC-GHG estimates in a wholly distinct SC-GHG Report in no way mitigates the absence of any record that EPA meaningfully engaged with or responded to any of the comments already submitted to the IWG.

Further, while it remains unclear what the SC-GHG Report is or how EPA intends to use it, nowhere does EPA represent that the report is in draft form or that the Agency will revise the SC-GHG Report based on comments and data received. On the contrary, EPA states that the "report presents new estimates of the SC-GHG" that EPA may rely upon "while [the IWG] process continues."[200] Therefore, if EPA intends to use and rely on the values in the SC-GHG Report as they are currently estimated, the Agency's solicitation of comments at this point does not truly "allow for public participation and an open exchange of ideas."[201] Nor is such an approach consistent with the National Academies' recommendation that draft revisions to the SC-GHG methods and estimates should be subject to public notice and comment, allowing input and review from a broader set of stakeholders, the scientific community, and the public.[202]

4. EPA has not Provided Interested Parties the Time or Information Necessary to Solicit Detailed and Constructive Feedback

In order for its public comment process to be reasonable and therefore lawful, EPA must provide commenters access to the data, studies, and other records on which the Agency relied as well as reasonably adequate time to review the data and draft comments analyzing EPA's conclusions and findings based on those records. EPA's present solicitation of comments on the SC-GHG Report does not satisfy either of these requirements.

The U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") makes clear that when an agency relies on data that is critical to its decision-making process, that data must be disclosed in order to provide the public an opportunity to meaningfully comment on the agency's rulemaking rationale.[203] Indeed, the D.C. Circuit has consistently maintained that "[i]n order to allow for useful criticism it is especially important for the agency to identify and make available *technical studies and data* that it has employed in reaching the decisions to propose particular rules."[204]

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[197] SC-GHG Report at 8.

[198] *Indep. U.S. Tanker Owners Comm v. Lewis*, 690 F.2d 908, 919 (D.C. Cir. 1982).

[199] *Advocates for Hwy & Auto Safety v. Fed. Hwy. Admin*., 28 F.3d 1288, 1292 (D.C. Cir. 1994) (citing *McLouth Steel Products Corp. v. Thomas*, 838 F2d 1317, 1323 (D.C. Cir. 1988)).

[200] SC-GHG Report at 84.

[201] E.O. 13563 at Sec. 1(a).

[202] National Academies of Sciences, Engineering, and Medicine 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*: Washington, DC: The National Academies Press ("NASEM 2017") at Pages 58-60.

[203] *See, e.g., Conn. Light & Power Co. v. Nuclear Regulatory Comm'n,* 673 F.2d 525, 530 (D.C. Cir. 1982); *Chamber of Commerce v. SEC,* 443 F.3d 890, 899 (D.C. Cir. 2006); *Am. Radio Relay League, Inc. v. FCC,* 524 F.3d 227, 236-37 (D.C. Cir. 2008).

[204] *Conn. Light & Power Co.,* 673 F.2d at 530 (emphasis added); *See also Am. Radio Relay League, Inc.,* 524 F.3d at 237 ("It would appear to be a fairly obvious proposition that studies upon which an agency relies in promulgating a rule must be made available during the rulemaking in order to afford interested persons meaningful notice and an opportunity for comment.").

Moreover, because of the "complex scientific issues involved in EPA rulemaking" Congress established more rigorous requirements under the CAA for making information available for public scrutiny.[205] Hence, the CAA mandates that "[a]ll data, information, and documents . . . on which the proposed rule relies *shall* be included in the docket on the date of publication of the proposed rule."[206] This critical requirement is particularly relevant here because EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, which is a rulemaking pursuant to the CAA.[207]

Therefore, if "documents of central importance upon which EPA intended to rely had been entered in the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."[208] "The Congressional drafters, after all, intended to provide 'thorough and careful procedural safeguards . . . [to] insure an effective opportunity for public participation in the rulemaking process.'"[209]

Notwithstanding this requirement, EPA's docket omits several studies, records, and other materials that appear fundamental to the Agency's development of the SC-GHG Report. For instance, EPA claims to have based several aspects of the SC-GHG Report on "the public comments received on individual EPA proposed rulemakings and the IWG's February 2021 TSD,"[210] but only identifies two supportive comments of the 88 total comments submitted on the 2021 TSD.[211] EPA did not identify or provide any comments "it received on individual EPA proposed rulemakings." Therefore, the Agency's administrative record for the SC-GHG Report is either insufficiently comprehensive or EPA impermissibly "rel[ied] on some comments while ignoring comments advocating a different position."[212]

Similarly, the SC-GHG Report relies extensively on SC-GHG estimation and modeling approach developed by RFF,[213] but while EPA's administrative record includes the RFF paper itself, it does not include all the data and studies that RFF utilized in developing those projections and estimates that EPA incorporated into its SC-GHG Report. For instance, RFF augments their economic forecast and generates their emissions forecast based on expert opinion,[214][215] but EPA's administrative record does not appear to contain any details or documentation regarding the expert elicitation and forecasting that was a key part of RFF's modeling effort. Given the critical importance of these forecasts in modelling the SC-GHG and EPA's implicit adoption of the forecasts in the SC-GHG Report, EPA should provide the public with details regarding how and why these experts were selected. For example, EPA should submit for public comment in the docket for the Proposed NSPS Revisions RFF's documentation, which details RFF's survey methodologies, partial selection methodology, and results. EPA should also extend the time period for submission of public comments on EPA's SC-GHG Report. Additionally, EPA should foster transparency by clarifying how RFF selected their experts from RFF's nominee pool.

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[205] *E.g., Small Ref. Lead Phase-Down Task Force v. EPA,* 705 F. 2d 506, 518 (D.C. Cir. 1983).

[206] CAA § 307(d)(3) (emphasis added); *see Kennecott Corp. v. EPA,* 684 F. 2d 1007, 1018 (CAA § 307(d)(3) requires EPA to place in the docket "the factual data on which the proposed regulations are based").

[207] 87 Fed. Reg. at 74,713.

[208] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (D.C. Cir.1981); *See also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C.Cir. 1982) (EPA improperly placed economic forecast data in the record only one week before issuing its final regulations).

[209] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (citing H.R.Rep.No.95-294, 95th Cong., 1st Sess. 188 at 319 (1977)).

[210] SC-GHG Report at 26, 37, 53, and 8.

[211] SC-GHG Report at 14 (FN26), and 15 (FN37).

[212] *National Women's Law Center v. Office of Management and Budget*, 358 F. Supp. 3d 66, 91 (D.D.C. 2019).

[213] Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. Brookings Papers on Economic Activity. Fall 2021, pp.223-305.

[214] Rennert et al.'s economic growth survey included the following participants: Daron Acemoglu, Erik Brynjolfsson, Jean Chateau, Melissa Dell, Robert Gordon, Mun Ho, Chad Jones, Pietro Peretto, Lant Pritchett, and Dominique van der Mensbrugghe.

[215] Rennert et al.'s future emissions survey included the following participants: Sally Benson, Geoff Blanford, Leon Clarke, Elmar Kriegler, Jennifer Faye Morris, Sergey Paltsev, Keywan Riahi, Susan Tierney, and Detlef van Vuuren.

More fundamentally, as discussed in Section III.a.1, EPA's administrative record does not even sufficiently apprise the public as to why EPA developed the SC-GHG Report or how the Agency intends to use it. However, even if EPA had timely provided all of the documents of central importance upon which it relied in drafting the SC-GHG Report, the public comment period EPA provided remains woefully insufficient. The SC-GHG Report provides a completely new set of SC-GHG estimates that were generated through a substantially revised modular approach using entirely different methodologies, models, studies, data, and analytical framing decisions than have been used by the IWG. And while EPA has not populated the administrative record with the full universe of the centrally important records on which it relied, there are hundreds of sources cited in the SC-GHG Report and the RFF Study that provided significant portions of the analysis used in the SC-GHG Report. As evidenced by the five years it took RFF to develop its SC-GHG estimates[216] and the fact that the IWG is more than a year overdue in developing the final SC-GHG estimates required by E.O. 13990, reviewing SC-GHG estimates and their underlying methodologies and data is incredibly labor-intensive and time-consuming.

As such, EPA's decision to provide the public only 69 days to review, develop, and submit comments on the SC-GHG Report is plainly unreasonable – particularly so, given that the comment period coincided with the holiday season. EPA's comment deadline for the SC-GHG Report is also unreasonable because it is the same comment period through which EPA is soliciting comments on the Proposed NSPS Revisions. The proposed revisions are complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under the CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, the current comment deadline is insufficient for even the Proposed NSPS Revisions alone.

In sum, EPA's current administrative record and comment deadline for the SC-GHG Report do not reasonably "allow for public participation and an open exchange of ideas."[217] API therefore respectfully requests that EPA supplement the administrative record with all of the centrally relevant information EPA utilized in developing the SC-GHG Report and provide a new and substantially longer comment period focused exclusively on the SC-GHG Report and the estimates contained therein.

b. Technical Issues with EPA's Methodology and Presentation of the SC-GHG Estimates

In addition to the procedural issues API described in the preceding subsection, our review of the SC-GHG Report raised several significant questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. It is critical the SC-GHG Report completely and transparently explain the precise bases for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Moreover, given the enormous and continually growing body of data and academic literature relevant to estimating the SC-GHG, the process by which EPA selects the data and literature on which it relies must be rigorous, objective, and transparent. Thus, when describing the evidentiary bases for its SC-GHG estimates, the SC-GHG Report should not only identify the studies on which the Agency relied, it must reasonably explain and describe why EPA declined to utilize other credible academic literature and data.

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[216] https://www.resources.org/archives/the-social-cost-of-carbon-reaching-a-new-estimate/?_gl=1*becwm3*_ga*OTczMDg2OTQzLjE2NzQ3NTAyOTI.*_ga_HNHQWYFDLZ*MTY3NDg0OTI4Ny4yLjEuMTY3NDg0OTMyMi4wLjAuMA.

[217] E.O. 13563 at Sec. 1(a).

The bullets below briefly describe a number of the questions and concerns that API and its members raised after reviewing the SC-GHG Report. Given the constrained timeframe for review and comment, these questions and concerns should by no means be considered exhaustive or complete. Rather, we urge EPA to view these questions and concerns as emblematic of API's broader concern with the manner in which the SC-GHG Report describes and supports EPA's model choices and SC-GHG estimation process.

- **Damage functions** – Two of the damage functions used in EPA's new SC-GHG model estimate damages at a subnational and/or sectoral level. However, there is no discussion about why EPA excluded other damage functions, particularly those produced by structural economy-wide models.[218] EPA should identify all the possible damage function approaches that could be incorporated and discuss the relative merits and shortcomings of each so stakeholders can understand EPA's rationale for their selected approach.

  Furthermore, given the relative importance of mortality-related impacts in the two sectoral damage functions, EPA should place more attention on how response functions could be adjusted for differences in age distributions across regions. Carleton *et al.* 2020 demonstrated that the temperature-mortality response function differs substantially by age, with a particularly strong relationship observed in the 65+ population. While age is included as a covariate in some of the studies included in Cromar *et al.* 2022, it is not uniformly considered across the literature assessed there. For example, the studies that do adjust for age do not present full mortality results by age. Cromar *et al.* did not consider heterogeneity by age group in their models estimating future mortality associated with temperature changes even though some of the individual studies included in Cromar *et al.* accounted for age. The ideal temperature-mortality model and subsequent monetization would account for age group heterogeneity at all stages of the analysis and calculations.

  Additionally, the temperature-mortality function for a given location and population will likely change through implementation of adaptation measures, a critical consideration in the SC-GHG estimation for mortality. However, adaptation is not consistently incorporated into these studies; and those studies that include adaptation vary in the way it is incorporated. In Carleton *et al.* 2020, administrative level 2 gross domestic product ("GDP") per capita and mean annual temperature for each location incorporates adaptation such that the location-specific exposure-response curve accounts for heterogeneity in adaptation response. Cromar *et al.* did not incorporate adaptation measures at a global or region-specific level, despite stating the importance of incorporating adaptation. As these measures will vary by many factors, including the regional climate and socioeconomic status, it is important that any future projections of the temperature-mortality function account for potential adaptation to temperature change, and the ideal study would account for adaptation at the local level.

- **Discount rate** – There are several choices regarding the discount rate that deserve more consideration and discussion. First, EPA should more fully justify its claim that long-term structural breaks in the interest rate imply lower interest rates in the future.[219] EPA should also explain how near-term interest rates from the last thirty years can fully inform the choice of an appropriate discount rate for the SC-GHG given the projection horizon of 300 years. Other work[220] has considered interest rates over long-time horizons and disputed the notion of structural breaks which calls into question some of EPA's discount rate assumptions. Furthermore, EPA should

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[218] Rose, S, D Diaz, T Carleton, L Drouet, C Guivarch, A Méjean, F Piontek, 2022. Estimating Global Economic Impacts from Climate Change. In Climate Change 2022: Climate Impacts, Adaptation, and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the IPCC, Chapter 16.

[219] *See* SC-GHG Report at 59.

[220] Rogoff et al. 2022. Long-Run Trends in Long-Maturity Real Rates 1311-2021. National Bureau of Economic Research.

explain their rationale for using a single discount rate for all regions, given that certain parameters used to estimate it, such as the economic growth rate, clearly vary across regions.

Second, since EPA estimates Ramsey parameters using assumptions about these near-term interest rates, EPA should consider whether the implied Ramsey parameters are reasonable and consistent with other available information. For example, the pure rate of time preference (ρ) that EPA estimates under the 2 percent near-term discount rate (0.2 percent) is significantly lower than those found in the Drupp *et al.*[221] survey cited in the SC-GHG Report.[222] Moreover, the value of ρ under the 1.5 percent near-term discount rate is near-zero, even though as EPA notes "it has been argued that very small values of ρ can lead to an unreasonable rate of optimal savings (Arrow et al. 1995), particularly with η around 1 (Dasgupta 2008, Weitzman 2007)."[223] Such results further call into question the choice of near-term discount rates and the reasons why parameters such as the Ramey parameters were forced to accommodate particular near-term discount rates, rather than the opposite.

Third, related to the calibration, EPA should state and explain how it calculates the near-term real growth rate of consumption per capita (g_t) as this is one of the few elements within the Ramsey discount rate that is observable in the market. To recover EPA's Ramsey parameters, a near-term consumption per capita growth rate of around 1.45 percent would seemingly be needed. Given that EPA appears to use the GDP per capita growth rate as a proxy for the consumption per capita growth rate, it is unclear why EPA derives its consumption per capita rate as the EPA notes "in the past decade average global per capita growth rates have been closer to 2%,"[224] and over the longer term global per capita growth rates have been higher. Once again, such results call into question why the growth rate was forced to accommodate other assumptions, rather than the opposite, given that the growth rate is the most observable of all the terms in the Ramsey equation.

Fourth, EPA should clarify how it estimates the near-term consumption growth rate "net of baseline climate change damages," and provide a practical example of how it calculated the consumption growth rate "net of baseline climate change damages" beyond what is offered in Appendix 3 of the SC-GHG Report. Moreover, EPA should discuss how climate damages affect the growth rate. If damages are assumed to impact investment (which would affect future economic output, and thus the growth rate), this seems to contradict EPA's assumption that damage functions are specified in consumption-equivalent units.[225]

Fifth, given the assumption of a constant savings rate, EPA should explain the basis for the specific savings rate and the methodology used. Similarly, EPA should discuss how the SC-GHG estimates would change if the savings rate varied at the national or regional given historical trends.

- **Geographic scope and reporting** – EPA lists several reasons for selecting a global SC-GHG—including the potential impacts on U.S. citizens living abroad, U.S. overseas military bases and investments, and regional destabilization caused by climate change. However, non-US impacts estimated by the damage functions used by EPA do not correspond to these impact categories. For example, total non-US mortality damages are not a reasonable estimate of the impacts on U.S. citizens living abroad. Therefore, EPA should consider and discuss reasonable alternatives for estimating potential impacts to U.S. interests that occur in other countries. In

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[221] Drupp *et al.* 2018. Discounting Disentangled. American Economic Journal: Economic Policy, 10 (4): 109-34.

[222] For the 1.5 percent consumption discount rate, EPA sets ρ to 0.01 percent and η to 1.02. For the 2 percent consumption discount rate, EPA sets ρ to 0.20 percent and η to 1.24. For the 2.5 percent consumption discount rate, EPA sets ρ to 0.46 percent and η to 1.42. Drupp *et al.*'s survey found that respondents' answers suggest a mean ρ value of 1.1 percent with a standard deviation of 1.47 and a median value of 0.5 percent.

[223] Drupp *et al.* 2018 at 61.

[224] SC-GHG Report at 22.

[225] *See* SC-GHG Report at 53.

addition, while EPA holds that not all spillover costs are properly attributed in regional breakdowns, as discussed further in Section III.c.1. below, the public would still benefit from SC-GHG estimates reported regionally, consistent with Circular A-4. EPA's SC-GHG Report also assumes that U.S. GHG mitigation activities, such as emissions pledges and the use of the global SC-GHG, engender international reciprocity. However, if EPA justifies the use of the global SC-GHG based on these factors, then the Agency should explain why its global emissions projection does not reflect globally coordinated action. Reasonable alternatives that maintain consistency between the geographic scope and the emissions trajectories should be considered and discussed.

- **Incorporation into regulatory cost-benefit analysis** – Given EPA's selection of a 1.5, a 2, and a 2.5 percent near-term discount rate, EPA's proposed SC-GHG discount rates no longer correspond to the typical regulatory consumption discount rate of 3 percent. Additionally, EPA's Ramsey discount rate approach further diverges from the constant discount rate approach used throughout federal cost-benefit analyses. Given that the announced revisions to Circular A-4[226] have not been finalized, API believes that it is inappropriate to incorporate EPA's new SC-GHG estimate in regulatory analysis until Circular A-4 is updated, as it is difficult to understand how EPA's SC-GHG approach for estimating climate benefits could be reasonably combined with other estimated benefits and cost streams discounted at different rates following standard A-4 guidance. For example, were EPA or another agency to use the EPA's SC-GHG estimates to present new benefit estimates in an RIA without updating the cost side of the ledger using the same near-term consumption discount rate used in the SC-GHG Report, the inconsistency between the discount rates used for benefits and costs would bias the cost-benefit analysis and undercut the rationality of the RIA's conclusions.

  EPA discusses the shadow price of capital, the preferred approach by Circular A-4, in Appendix 2 of the SC-GHG Report; however, EPA does not discuss whether or how the Agency plans to use this method in future cost-benefit analyses. To apply this method consistently, both benefits and costs must be adjusted in a similar manner. Whether this overall approach, or the revised discount rates themselves will improve cost-benefit analyses depends on whether and how Circular A-4 is updated to ensure consistency in how costs and benefits are estimated and compared. To avoid exacerbating inconsistencies, EPA should acknowledge this dependency and avoid using revised estimates until OMB guidance is updated, and all reviews are completed.

- **Underestimation of the SC-GHG** - EPA states that "The modeling implemented in this report reflects conservative methodological choices, and, given both these choices and the numerous categories of damages that are not currently quantified and other model limitations, the resulting SC-GHG estimates likely underestimate the marginal damages from GHG pollution."[227] This claim is repeated throughout EPA's SC-GHG Report. However, EPA should provide additional support for this assertion by listing and explaining the range of possible options and how the specific approach ultimately adopted by the Agency represents a conservative methodological choice. Repeating these assertions throughout the SC-GHG Report prior to completion of the IWG's peer review process may hamper objective analysis and may bias the IWG's review.

- **Market rates vs. purchase power parity** – EPA's SC-GHG Report states that "the shift to PPP-based projections in the RFF-SPs . . . represents another advancement in the science underlying the SC-GHG framework presented in this report."[228] However, Bressler and Heal (2022) contend that using "purchasing-power parity is incompatible with a pure Kaldor-Hicks approach."[229] Specifically, Bressler and Heal provide an example in which

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[226] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.
[227] SC-GHG Report at 2.
[228] SC-GHG Report 25.
[229] Bressler R., and Geffrey Heal. 2022. Valuing Excess Deaths Caused by Climate Change. National Bureau of Economic Research

a regulation would generate net costs when analyzed in PPP-adjusted dollars but would generate net benefits when analyzed using market exchange rates. EPA should therefore explain how using PPP-adjusted dollars is compatible with the federal government's overall approach to cost-benefit analysis.

c. The SC-GHG Report Should Fully and Explicitly Discuss the Limited Utility of the SC-GHG Estimates

EPA's SC-GHG Report avers that the SC-GHG estimates allow "analysts to incorporate the net social benefits of reducing emissions of greenhouse gases (GHG), or the net social costs of increasing such emissions, in benefit-cost analysis and, when appropriate, in decision-making and other contexts."[230] API agrees that from its earliest development by the IWG, the SC-GHG "was explicitly designed for agency use pursuant to E.O. 12866."[231] That is why the titles of each of the six TSDs the IWG published prior to the 2021 TSD disclaimed that they were "for Regulatory Impact Analysis under Executive Order 12866."[232]

While API agrees with the SC-GHG Report's statement that SC-GHG estimates are used in benefit-cost analysis, we believe EPA should clarify and describe the "decision-making and other contexts" the Agency believes may appropriately be based on SC-GHG estimates.[233] API agrees with the need to take action on climate change and we agree that agencies generally should weigh costs and benefits when considering such actions, but given the significant uncertainty and recognized malleability of SC-GHG estimates through modest changes to one or a few inputs, we cannot support expanded use of the Agency's or the IWG's SC-GHG estimates beyond their originally intended application in cost-benefit analysis. Indeed, in addition to, and in fact because of, the ease with which they can be "manipulated to reflect preferences, philosophies, assumptions, and so on,"[234] the SC-GHG estimates reflect such a broad range of uncertainty that in some contexts they may not effectively assist agencies' broad weighing of costs and benefits, as envisioned in E.O. 12866.

The SC-CH_4 values in EPA's SC-GHG Report and the IWG's 2021 TSD illustrate how agencies can struggle to use the estimates to determine whether a particular course of action will deliver more benefits than costs or *vice versa*. In the SC-GHG Report, the "nine separate distributions of estimates"[235] for avoided SC-CH_4 damages in 2030 range from $1,100 per metric ton to $3,700 per metric ton.[236] The 2021 TSD's estimates for avoided SC-CH_4 damages in 2030 range even more widely from $940 per metric ton to $5,200 per metric ton.[237] From a policy and regulatory perspective, the difference between $940 and $5,200 per metric ton or even $1,100 and $3,700 per metric ton is immense. A regulatory action that is imminently justifiable to mitigate damages estimated at the higher end of these ranges may be preposterous if proposed to avoid damages estimated at the lower end of these ranges.

"Such a wide range of . . . SC-CO_2 estimates is little more than a mathematical affirmation of the federal court's judgment that 'the value of carbon emissions reductions is certainly not zero.'"[238] "However, for the purpose the .

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[230] SC-GHG Report at 1.

[231] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[232] *See* 2010 TSD; May 2013 TSD; May 2013 TSD (revised); November 2013 TSD; August 2016a TSD (for CO_2); and August 2016b TSD (for Methane and Nitrous Oxide).

[233] API urged the IWG to provide the same clarification on multiple occasions.

[234] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 366.

[235] SC-GHG Report at 66.

[236] SC-GHG Report at 68.

[237] 2021 TSD at 5.

[238] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

. SC-CO_2 was developed— . . .RIAs[] for US federal regulations—such a wide range of SC-CO_2 is not necessarily a problem."[239]

The Electric Power Research Institute ("EPRI") examined 65 federal rules and 81 subrules between 2008 and 2016 that utilized the IWG's SC-CO_2 estimates in their regulatory analyses.[240] EPRI found that "the inclusion of benefits from policy-induced CO_2 emissions changes does not change the sign of net benefits. In other words, the net benefits are positive with and without consideration of CO_2 reduction benefits."[241]

Thus, while the broad range of uncertainty inherent in the IWG's SC-GHG estimates would appear to preclude their use in most cost-benefit analyses, in practice, the estimates have been used in analyses in which the difference between costs and benefits was larger than the SC-GHG estimates' range of uncertainty. This demonstrates that for those actions with non-climate benefits that are already estimated to exceed costs by a substantial margin, the IWG's SC-GHG estimates' range of uncertainty will not matter.

The extent of uncertainty and speculation that besets the SC-GHG estimates developed by the IWG and EPA alike precludes their reduction to a single value, be it a central value or otherwise. The IWG's SC-GHG estimates "were developed . . . with a methodology to fit the specific purpose of a benefits estimate to be added to a regulatory impact analysis . . ."[242] While EPA's SC-GHG Report adopts a modular approach in lieu of reliance on the IAMs used by the IWG, the reality of the SC-GHG estimation process is "that a high degree of uncertainty is baked in and cannot reasonably be estimated away."[243] At best, this enterprise is capable of producing "a very wide range of potential" SC-GHG estimates.[244]

> In aggregate, the SCC estimates developed by the interagency working group and others represent a strange marriage of conventional economic-financial logic, arbitrary economic-financial logic, massively expansive biophysical phenomena, preference, and uncertainty management utilized to create a digestible input – a dollar amount – for use in the dominant cost-benefit analysis . . . framework.[245]

Moreover, the subjective judgements that are necessary inputs into the SC-GHG estimation process make the product of those modeling exercises malleable. Indeed, SC-GHG estimates "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[246] Thus, "[f]or these assumptions, the tools of science, economics, or statistics are incapable of providing a 'best' or single value."[247]

> [P]roducing a wide range of SC-CO_2 estimates is simply the best we can do using this methodology, and it is the best we will ever be able to do. The . . . Central SC-CO_2 is not an optimal price of CO_2 emissions or a best estimate of the benefits of CO_2 reductions. It is a noncomprehensive estimate

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[239] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[240] Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.

[241] Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.

[242] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[243] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 364-5.

[244] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[245] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 348.

[246] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 369.

[247] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

> of the benefits of GHG reductions using one set of assumptions that is arguably defensible given the theoretical and methodological challenges associated with the approach.[248]

In addition to the methodological limitations precluding the use of the SC-GHG estimates in royalties, subsidies, fees, or applications that require a single value or narrow range of uncertainty, there are legal, statutory, and practical constraints on more expansive use of SC-GHG estimates as well. Indeed, courts have generally only upheld agencies' use of the SC-GHG estimates in the context of cost-benefit analyses.[249]

While some courts have held that agencies must estimate the costs of GHG emissions when assessing impacts of their proposed actions under the National Environmental Policy Act ("NEPA"), the agencies' impact assessments in those cases typically included cost-benefit analyses that are not required by NEPA.[250] In other words, because the agencies there estimated quantified benefits of certain actions, they also had to estimate quantified costs including of GHG emissions. In many other cases, courts have held that agencies have no obligation to use the SC-GHG estimates in analyzing impacts under NEPA.[251] Indeed, many of these courts took favorable views of agency determinations that SC-GHG estimates are ill-suited for NEPA analyses based on uncertainty ranges or otherwise.[252] Courts have generally taken a similar view to the Federal Energy Regulatory Commission's ("FERC's") prior position that the SC-GHG estimates' broad variability range makes them unsuited for public interest determinations[253] under the Natural Gas Act.[254] And in the context of collecting royalties and other financial obligations related to the leasing, production, and sale of minerals from federal and Indian lands, the federal government is affirmatively prohIbited from considering the SC-GHG estimates.[255]

Indeed, regardless of whether the Administration continues to rely on the IWG's estimates or those newly proffered by EPA in the SC-GHG Report, the SC-GHG estimates' broad range of variability and uncertainty render them inappropriate for use in any project-level or site-specific application. In addition, while analyses at these scales might be capable of monetizing some impacts (such as projected climate impacts), partial monetization is not advisable for several reasons. First, it could be interpreted as emphasizing or de-emphasizing the monetized impact, even though there is no basis on which to conclude that a monetized impact is more or less significant than a non-monetized impact. Second, monetized benefits and costs are only meaningful when they are compared to one another in aggregate.

These considerations illustrate the material distinction between formalized cost-benefit analysis in the regulatory context and other types of analysis. Whereas monetization is essential for regulatory analyses, it is potentially misleading outside this application for reasons discussed above. Notably, this material distinction is also embodied

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[248] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[249] Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 416.

[250] *High Country Conservation Advocates v. U.S. Forest Serv.*, 52 F. Supp. 3d 1174,1181, 1184 (D. Colo. 2014); *See also Mont. Envtl. Info. Ctr. v. U.S. Office of Surface Mining*, 274 F. Supp. 3d 1074, 1096-98 (D. Mont. 2017); *See also Citizens for a Healthy Community v. BLM*, 377 F.Supp. 3d 1223 (D. Col. 2019); *Contrast with WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41; *See also* Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 415.

[251] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020); *See also Citizens for a Healthy Cmty v. U.S. Bureau of Land Mgmt.*, 377 F. Supp. 3d 1223, 1239-40 (D. Colo. 2019); *See also WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 76 (D.D.C. 2019); *See also Wilderness Workshop v. U.S. Bureau of Land Mgmt.*, 342 F. Supp. 3d 1145, 1159 (D. Colo. 2018); *High Country Conservation Advocates v. Forest Service*, 333 F. Supp. 3d 1107 (D. Colo. 2018); *See also W. Org. of Res. Councils v. U.S. Bureau of Mgmt*., No. CV 16-21-GFBMM, 2018 WL 1475470, at *13 (D. Mont. Mar. 26, 2018).

[252] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020).

[253] *See* Natural Gas Act,15 U.S.C. § 717f(a), (c) (2012).

[254] *See, EarthReports, Inc. v. Fed. Energy Reg. Comm'n*, 828 F.3d 949,. 953-54 (D.C. Cir. 2016); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 867 F.3d 1357, 1375 (D.C. Cir. 2017) (remanding to FERC for a discussion of whether it still holds the *EarthReports* position); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 672 Fed. Ap 'x 38 (D.C. Cir. 2016).

[255] *See Wyoming v. Jewell*, No. 2:16-CV-0285-SWS (Oct. 10, 2020); *See also* 86 Fed. Reg. 31,196, 31,206 (June 11, 2021).

in E.O. 12866, which distinguishes between "regulatory actions" and "significant regulatory actions" based in part of the projected scale of impact.[256] For each "significant" proposed action, the issuing agency is required to provide a cost-benefit analysis. Thus, existing regulatory guidance essentially equates significance with the need for cost-benefit analysis, which in turn, implies full monetization of costs and benefits. While (as discussed above), there are inherent limits to the usefulness of SC-GHG estimates in rulemaking, consideration of SC-GHG values is sensible in situations where all costs and benefits are monetized. Consideration of the SC-GHG estimates is not appropriate in instances where only a subset of impacts can be monetized; accordingly, restricting its use to significant regulatory actions ensures consistency with this principle.

d. **The SC-GHG Report Needlessly Limits the Utility of EPA's SC-GHG Estimates by Failing to Present Domestic SC-GHG Estimates Alongside Global Estimates**

In order to conduct a valid and legally-defensible cost-benefit analysis, agencies must ensure that they weigh costs and benefits of the same scale and of the same type. Therefore, consistent with API's repeated requests to the IWG, API recommends that EPA's SC-GHG Report present domestic SC-GHG estimates alongside global estimates. Indeed, we believe that, absent a clear congressional directive otherwise, agency cost-benefit analyses should be constructed to weigh domestic costs against domestic benefits. By doing so, agencies can better ensure that projected domestic impacts alone justify the costs to be imposed on domestic industries. When agencies have failed to do so and weighed domestic costs against global benefits, they have effectively put their thumb on the scale in favor of regulatory action. Such an analysis is not only inconsistent with basic economic principles it overlooks "the more prosaic commonsense notion that Congress generally legislates with domestic concerns in mind."[257]

Given that EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, the CAA provides a particularly relevant example of why the geographic scope of agencies' regulatory analyses should reflect the intended scope under which the regulation is proposed or promulgated.[258] In CAA Section 101(b)(1), Congress expressly stated that the statute's purpose is to "protect and enhance the quality of the *Nation's* air resources so as to promote the public health and welfare and the productive capacity of *its population*."[259] By focusing on "the Nation" and "its population," Congress clearly demonstrated that it enacted the CAA to affect domestic air quality.

This interpretation of the CAA is not new, nor does it fail to reflect the global nature of climate change. Indeed, EPA relied on this interpretation when it issued the highly important Endangerment Finding on which multiple federal climate change regulatory actions have been based.[260]

In addition to the clear inferences that can be drawn from Congress' statements of statutory intent, the text of specific provisions of the statute confirms that Congress intended to limit the reach of the Act to domestic effects, unless it expressly provided otherwise. In only two discrete instances, Congress explicitly addressed the foreign effects of domestic air emissions in the CAA.

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[256] *See* E.O. 12866 at Sec. 3.

[257] *RJR Nabisco, Inc. v. Eur. Cmty.*, 136 S. Ct. 2090, 2100 (2016).

[258] 87 Fed. Reg. at 74,713.

[259] CAA § 101(b)(1) (emphasis added).

[260] *See* Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the CAA, 74 Fed. Reg. 66496, 66514 (Dec. 15, 2009) ("[T]he primary focus of the vulnerability, risk, and impact assessment is the United States").

First, in Title I of the Act, Congress authorized EPA to consider the foreign effects of domestic air emissions within the delineated framework of Section 115. There, Congress defined the process for EPA to evaluate and address reports of domestic air pollution possibly affecting public health or welfare in a foreign country.[261] Critically, this only applies when the Administrator finds there is "reciprocity" such that "the United States essentially [has] the same rights with respect to the prevention or control of air pollution occurring in that country as" Section 115 gives to the foreign country.[262]

Second, in Title VI of the CAA, Congress addressed the global impacts of domestic stratospheric ozone emissions by, among other actions, listing ozone-depleting chemicals of concern, establishing reporting requirements for manufacturers and other entities, and phasing out the production of certain chemicals.[263] Congress expressly enacted Title VI in 1990 in order to implement the Montreal Protocol on Substances that Deplete the Ozone Layer, an international treaty signed by the United States, which addresses stratospheric ozone.[264]

These two discrete provisions (Section 115 and Title VI) represent the full extent of EPA's authority to consider the international benefits of domestic regulation. Critically, these provisions demonstrate that, when Congress chose to allow the Agency to consider foreign impacts of domestic regulation, it said so expressly. These two provisions also reflect the very narrow purpose for which Congress allowed EPA to consider foreign impacts of domestic regulation. Both provisions deal with international agreements under which the United States and one or more foreign nations make reciprocal commitments to impose regulations within their borders that confer benefits outside their borders and/or to the other party.

In these two narrow circumstances, the United States is the beneficiary of EPA's action and also the foreign nation's reciprocal regulatory action. As such, while foreign impacts are considered, their consideration is solely intended to inform regulatory decisions seeking to maximize domestic benefits of reciprocal regulatory actions. The executive branch has ample authority to act for the benefit of foreign nations, but the CAA is generally not one of the statutes that confers that authority. With the exception of these two discrete provisions, the CAA arguably precludes EPA from weighing international benefits against domestic costs.[265]

In addition to the limitations that the CAA places on EPA specifically, OMB guidance applies these same principles government-wide. In support of limiting the use of international benefits for justifying regulation, OMB directs agencies developing regulatory analyses to focus on the "benefits and costs that accrue to citizens and residents of

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[261] CAA § 115(a)-(b).

[262] CAA § 115(c).

[263] EPA, 1990 CAA Amendment Summary: Title VI (Jan. 4, 2017), https://www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary-title-vi.

[264] 42 U.S.C. § 7671m(b) ("This subchapter as added by the CAA Amendments of 1990 shall be construed, interpreted, and applied as a supplement to the terms and conditions of the Montreal Protocol.").

[265] Settled principles of statutory interpretation further confirm that Congress did not intend to authorize EPA to rely on the foreign effects of U.S. emissions in promulgating regulations under the CAA. For one, statutes are construed to give effect to all provisions. *See, e.g., Hibbs v. Winn*, 542 U.S. 88, 101 (2004) ("A statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or superfluous, void or insignificant….") (citations omitted). Section 115 would effectively be a nullity if EPA read the Act to provide the Agency with the authority to consider effects of domestic emissions on foreign countries without following the Section 115 process. Moreover, it is also a well-settled canon that if Congress addressed an issue in one provision, its failure to address that same issue elsewhere confirms its limited intent. *See, e.g., Russello v. United States*, 464 U.S. 16, 23 (1983) ("[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (citations omitted).

the United States"[266] and directs agencies which "choose to evaluate a regulation that is likely to have effects beyond the borders of the United States" to report those impacts "separately."[267] OMB's guidance further states that an agency's cost-benefit analysis "should focus on benefits and costs that accrue to *citizens and residents of the United States*."[268]

Notwithstanding that OMB Circular A-4 mandates agency consideration of domestic costs and benefits while simply allowing for optional consideration of non-U.S. benefits, EPA's SC-GHG Report omits any calculation of domestic benefits. In lieu of this important, and arguably mandatory presentation of domestic benefits, the SC-GHG Report merely offers the EPA's justification for its absence.[269] While these justifications are perhaps sufficient to support the EPA's decision to present global benefits in the SC-GHG Report, none explain the Agency's refusal to also present an estimate of domestic benefits alongside the global value.

For instance, the IWG argues that analyzing the global benefits of U.S. regulatory actions can help generate reciprocal actions from other countries and "allows the U.S. to continue to actively encourage other nations . . . to take significant steps to reduce emissions."[270] Even assuming such effect occurs, the goal of the SC-GHG estimation process should not be the development of tools to aid in international negotiations or which help the U.S. "actively encourage" reciprocal actions on climate change; President Biden required use of the "best available economics and science"[271] to estimate as accurately as possible the societal costs of adding a small increment of GHG into the atmosphere in a given year. To the extent EPA is attempting to assume the IWG's assigned role of developing SC-GHG estimates, the Agency must also assume the obligation to dispassionately and objectively estimate the SC-GHGs using "best available economics and science."[272] And that obligation cannot be construed to encompass an advocacy role. Even if it were reasonable for EPA's interest in advocating for intergovernmental cooperation to shape how it estimates the SC-GHG, the EPA's SC-GHG Report provides no explanation why that advocacy role would be undermined by the presentation of domestic benefits *alongside global benefits*.

EPA also offers that:

> The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to the U.S. population.[273]

Although the U.S. could be adversely impacted by potential climate change damages that could occur in other countries, it does not follow that the EPA must therefore include the potential *damages in those other countries* as part of the SC-GHG estimate. Rather, the Agency should include in the SC-GHG estimates the potential *domestic impact* of those reasonably projected extraterritorial climate damages. As explained by the NASEM:

> Correctly calculating the portion of the SC-CO_2 that directly affects the United States involves more than examining the direct impacts of climate that occur within the country's physical borders . . .

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[266] OMB, Circular A-4, at 15.
[267] OMB, Circular A-4, at 15.
[268] OMB, Circular A-4, at 15 (emphasis added).
[269] *See* SC-GHG Report at 10-15
[270] SC-GHG Report at 14.
[271] E.O. 13990 at Sec. 5(b)(ii)(D).
[272] E.O. 13990 at Sec. 5(b)(ii)(D). Notably, and as previously discussed, E.O. 13990 expressly assigned the SC-GHG estimation development process to the IWG and precluded agencies from developing and using their own values.
[273] SC-GHG Report at 11.

> Climate damages to the United States cannot be accurately characterized without accounting for consequences outside U.S. borders.[274]

In other words, regardless of whether climate change imposes costs on the U.S. directly or indirectly through potential damages in other countries, the costs EPA should be attempting to characterize are those anticipated to be borne by the U.S. and its citizens. Thus, the global nature of climate change is consistent with and supported by the presentation of domestic benefits in the SC-GHG estimates. And the global nature of this issue certainly does not explain why the domestic benefits should not at least be presented alongside projections of global benefits.

EPA's final rationale for declining to present domestic benefits alongside global values is that there are relatively few region- or country-specific SC-GHG estimates or models with sufficient resolution to estimate SC-GHG benefits on a country-specific basis.[275] At the same time, EPA has largely limited its own consideration of damage functions to those that can be specified at the national or sub-national level, suggesting that domestic impacts could be reasonably estimated in two of the three frameworks adopted.[276] Although we agree that there is a high level of uncertainty in the regional or country-specific SC-GHG estimates, we believe it is inconsistent for EPA to use this uncertainty to rationalize its decision to decline to provide any SC-GHG estimates other than global, particularly given EPA's decision to severely restrict consideration of damage functions to precisely those that provide such information. Uncertainty and speculation pervade every aspect of the SC-GHG estimates, and the Agency should explain why such uncertainty provides a valid basis to decline to render estimates in this instance, but presents no barrier in every other respect.

It is also increasingly inaccurate for EPA to cite the overall paucity of literature on regional and country-specific SC-GHG estimates. As noted by the NASEM in 2017:

> Estimation of the net damages per ton of CO_2 emissions to the United States alone, beyond the approximations done by the IWG, is feasible in principle; however, it is limited in practice by the existing SC-IAM methodologies . . .[277]

Indeed, EPA's SC-GHG Report identifies a number of new models and academic efforts that have enhanced our ability to model SC-GHG benefits with greater spatial resolution.[278] While these country-specific estimates remain highly uncertain and divergent, they all broadly agree that the SC-GHG in the U.S. is a small fraction of the SC-GHG Report's estimates of the global SC-GHG.

Although country-specific SC-GHG estimates remain quite imprecise, they are highly relevant because EPA and other agencies should not adopt rules which could impose massive costs on the U.S., but for which the claimed benefits primarily accrue overseas—certainly not without a clear and explicit directive from Congress. EPA's assertion that rule writers and policymakers use only the global SC-GHG estimates in cost-benefit analysis results in

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[274] NASEM 2017 at 52-53.

[275] SC-GHG Report at 77-80.

[276] SC-GHG Report at 39 ("Based on a review of available studies using these approaches, the SC-GHG estimates presented in this report rely on three damage functions. They are: 1. a subnational-scale, sectoral damage function estimation (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (CIL 2022, Carleton et al. 2022, Rode et al. 2021)), 2. a country-scale, sectoral damage function estimation (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert et al. 2022b)), and 3. a meta-analysis-based global damage function estimation (based on Howard and Sterner (2017)).").

[277] NASEM 2017 at 53.

[278] SC-GHG Report at 77-80.

a significant misalignment of costs and benefits, particularly for regulatory actions, like the Proposed NSPS Revisions, that are promulgated pursuant to the CAA.

As such, API's modest recommendation, which we have also previously voiced to the IWG, is not that the federal government abandon the global SC-GHG estimates, but that it simply present domestic SC-GHG estimates alongside global values. This approach would allow risk managers to more readily align the costs with the benefits. Consistent with OMB guidance, the costs of a rule for entities in the U.S. should be presented in comparison with the benefits occurring in the U.S.

IV. CONCLUSION

API appreciates the opportunity to provide these comments on EPA's SC-GHG Report. We hope this comment opportunity is the first step toward a more open and transparent process for developing SC-GHG estimates and the judgment and assumptions used to develop and portray those estimates.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, EPA's unilateral development of SC-GHG estimates raises a number of questions and concerns the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the IWG.

President Biden's issuance of E.O. 13990 on his first day in office reflects the importance of the SC-GHG estimates to our nation's climate policies and regulations. Given the importance of these estimates, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each module had been updated and the SC-GHG Report had been fully drafted. Moreover, given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is wholly insufficient for soliciting detailed feedback from informed stakeholders.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. In fact, EPA has not even clearly explained why it developed the SC-GHG Report or how it intends the SC-GHG Report's estimates to be used. Nonetheless, where possible, API has tried to provide EPA relevant analysis and constructive recommendations for improving the reliability and utility of the SC-GHG Report and the estimates therein. We did so, not only with the intent of improving the SC-GHG estimates and the process through which they are developed, but with the hope that by providing credible analysis and constructive feedback, EPA would more fully recognize the benefit of engaging stakeholders in a more open, data-driven, and collaborative process.

API recognizes the need to confront the challenges of climate change. However, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. Indeed, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.

Thank you again for your consideration of these comments. If you have any questions or would like to discuss these comments, please feel free to contact Andrew Baxter at (202) 268-2800 or baxtera@api.org.

Sincerely,

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Submitted via regulations.gov

January 31, 2022

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

ATTN: Docket ID EPA-HQ-OAR-2021-0317
Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" including Proposed 40 CFR 60, Appendix K

Dear Administrator Regan:

The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 FR 63110, November 15, 2021). This submittal includes comments on the associated proposed Appendix K to 40 CFR Part 60, "Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging".

API is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Reducing methane emissions is a priority for our industry and we are committed to advancing the development, testing, and utilization of new technologies and practices to better understand, detect, and further mitigate emissions. In recent years, energy producers have implemented leak detection and repair programs, phased out the use of high-bleed pneumatic controllers, and reduced emissions associated with flaring – voluntarily and under federal and state regulations. In addition, API supports industry-led initiatives, such as The Environmental Partnership, to build on the progress industry has made to reduce emissions and continuously improve environmental performance. Founded in 2017, The Partnership has grown to nearly 100 oil and natural gas companies committed to continuously improving their environmental performance by taking action, learning about best practices and technologies, and fostering collaboration. Collectively, the coalition represents over 70% of total U.S. onshore oil and natural gas production and the program is being implemented in 41 of 50 states. Each year, the participating companies report[1] their implementation of the program's six Environmental Performance Programs, including programs for leak detection and repair, gas-driven pneumatic controllers, liquids unloading, compressors, pipeline blowdowns and flare management.

API supports the cost-effective direct regulation of methane from new and existing sources across the supply chain, and directionally supports the EPA proposal to reduce VOC and methane emissions. We especially appreciate EPA's inclusion of an alternate fugitive emissions monitoring option that allows for use of advanced detection technologies. The ability to take advantage of new and emerging technologies allows for monitoring programs that can more effectively identify and address larger emission events. Our comments include suggestions to further enhance the alternate monitoring framework.

In our review of the proposal, API considered the effectiveness of emission reduction strategies, safety, feasibility, operability, and cost, and where appropriate, we have recommended alternative approaches. As no rule text has been provided in this initial proposal, our comments are based on our best understanding of the requirements as they have been described in the preamble. This assessment could be modified once the requirements are provided in EPA's supplemental proposal. We encourage EPA to provide adequate time for stakeholders to review and comment on the supplemental proposal that is accompanied by regulatory text.

As further outlined in our comments, we do not believe the proposal publication date can set the Subpart OOOOb new source applicability date because the proposal lacks proposed regulatory text. Without regulatory text, affected facilities cannot know with certainty what regulatory requirements EPA has proposed and are thus unable to reasonably plan to comply with the final rule. The new source applicability date should be set when proposed regulatory text is published in the Federal Register as part of EPA's supplemental proposal.

With respect to proposal requirements for new (NSPS OOOOb) and existing (EG OOOOc) sources, we generally support, with recommended changes to Appendix K and its application, the provisions for fugitive emissions monitoring at well sites, compressor stations, and gas processing plants. The proposed Appendix K Optical Gas Imaging (OGI) protocol is not appropriate for use in the production and transmission sectors, where OGI monitoring specifications should continue to be based on NSPS OOOOa requirements. With our recommended modifications to Appendix K, we support its application for gas processing plants, petroleum refineries, and similar facilities.

In addition to fugitive emissions monitoring requirements, we also generally support, with certain modifications, the proposal requirements for new and existing pneumatic pumps, storage vessels,

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[1] https://theenvironmentalpartnership.org/annual-reports/

reciprocating compressors, centrifugal compressors (other than existing centrifugal compressors located in Alaska), gas well liquids unloading, and oil well associated gas.

With respect to proposed requirements for pneumatic controllers, we generally support EPA's proposal for new and existing gas processing plants and for new well and compressor station surface sites, provided there is an option to route vented emissions to a control device. We provide recommended changes to the applicability of pneumatic controller requirements for existing well sites and compressor stations and to the definition of modification.

API's support of the EPA proposed requirements assumes that EPA provides adequate implementation schedules for certain types of modifications under OOOOb and for retrofitting existing sources under OOOOc.

API is committed to working with EPA and the Administration as it develops and finalizes regulations that are cost-effective, facilitate innovation and further the progress made in reducing emissions, to ensure that the oil and natural gas industry can continue to provide the world with the affordable, reliable energy it needs while reducing emissions and addressing the risks of climate change.

If you have any questions regarding the content of these comments, please contact Cathe Kalisz at kaliszc@api.org.

Sincerely,

Attachments

cc:
Joe Goffman - EPA
Tomas Carbonell - EPA
Peter Tsirigotis - EPA
David Cozzie - EPA
Steve Fruh - EPA
Karen Marsh - EPA
Amy Hambrick - EPA

API Comments on EPA's "Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"

(Proposed NSPS OOOOb, EG OOOOc and Proposed Appendix K)

Docket ID: EPA-HQ-OAR-2021-0317

January 31, 2022

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Attachment D – API Comments on EPA’s Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks

PROPOSED NSPS AND EMISSIONS GUIDELINES FOR THE OIL AND NATURAL GAS SECTOR (NSPS OOOOb AND EG OOOOc) INCLUDING PROPOSED APPENDIX K
DOCKET ID: EPA-HQ-OAR-2021-0317

1.0 INTRODUCTION

API supports the direct regulation of methane for new and existing oil and natural gas sources and remains committed to working with EPA and the Administration to identify cost-effective emission control opportunities. We support the goal of promoting environmental justice, and our members are committed to constructive interactions among industry, regulators, and surrounding communities that may be disproportionately impacted.

These comments provided herein focus on technical and feasibility challenges with certain provisions described by EPA for proposed NSPS OOOOb and EG OOOOc. Our members look forward to continued dialogue and engagement as EPA works towards the supplemental proposal.

The major concerns identified by our members during this initial comment period include the following:

- **EPA took a very rare step when it issued this preamble-only proposal. The absence of regulatory text underscores the need for EPA to reset the applicability date for the proposed rules.** The current proposal's NSPS OOOOb applicability date means the inventory of affected facilities is currently growing (particularly existing facilities that are modified) without known compliance obligations, as there is no formal regulatory text to follow. The new source applicability date should be set when proposed regulatory text is published in the Federal Register, and EPA must provide sufficient opportunities for public comment, including on elements of the currently available portion of the rule, when definitions, applicability, and other relevant details are available in regulatory text. Furthermore, given the lack of regulatory text and the short comment period timeframe, we have not had an opportunity to fully analyze the Regulatory Impact Analysis (RIA) and the overarching cost effectiveness of the proposed rule. We will continue to pursue and provide more detailed input when we see the regulatory text in the supplemental proposal.

- **OGI monitoring protocols for production facilities and compressor stations should be based on NSPS OOOOa requirements, not Appendix K.** While API supports the use of Optical Gas Imaging (OGI) technology, Appendix K as drafted is unnecessarily burdensome for utilization in upstream production facilities, gathering and boosting compressor stations, and transmission compressor stations. Comments offered below (refer to Comment 4.0) expand on our concerns and outline some of the initially identified feasibility challenges in greater detail. The requirements specified in NSPS OOOOa that are currently used by operators have consistently proven to be effective and are more appropriate for use in upstream applications. Accordingly, we recommend EPA revise its proposal to limit the applicability of Appendix K to refineries; gas plants; and, potentially, similar larger process operations in other industries.

- **Significant modifications to Appendix K are necessary for the protocol to be feasible for implementation at refineries and natural gas processing plants.** Included in Attachments A and B are comments and suggested edits to allow the Appendix K protocol to be effectively implemented for use at refineries and gas processing plants. API's recommended changes are intended to proactively address concerns that the proposed requirements will result in difficulty in finding and retaining adequate numbers of qualified senior OGI operators; that the monitoring, training, and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and that the ownership of various requirements, particularly the recordkeeping requirements, are unclear and unnecessarily burdensome. The recommended changes also aim to make the Appendix K requirements more straightforward and efficient.

- **While we support reducing emissions from pneumatic controllers, the proposed provisions for pneumatic controllers must be re-evaluated.** We support moving towards non-emitting controllers for completely new construction surface sites; however, EPA has made no provision for addressing modifications at existing locations. The technical feasibility and cost effectiveness for moving towards non-emitting controllers from gas driven controllers fundamentally changes how an operator would approach the control strategy and operation of assets. As such, we offer EPA our suggestions for addressing NSPS modifications and for the retrofit of existing facilities under Emission Guidelines (EG).

- **Advanced leak detection technologies should be specified as an alternative BSER in addition to use of OGI and Method 21 (M21).** Allowing new leak detection technologies increases flexibility in how operators identify leaks and other process upsets. Allowing alternate technologies to be considered BSER will facilitate continued innovation in methane detection technology capabilities.

- **Guidance issued to state programs along with the Emission Guidelines should allow a minimum 3-year implementation period.** Operators with thousands of oil and gas facilities will need adequate time to plan for retrofits and obtain control devices or other specialized equipment, all while dealing with potential supply shortages. Additionally, the precedent for recognizing and providing adequate phase-in is well established. For example, EPA existing source rules under NESHAP (Subparts HH and ZZZZ), which require replacement or retrofit of existing applicable sources in the oil and gas sector, provided a minimum 3-year phase-in to complete work and establish compliance. Some emissions sources like pneumatic controllers may require a longer implementation period (even longer than three years) depending on the finalized regulatory requirements. Lastly, the ongoing limitations of the global supply chain may likely hinder operators' ability to obtain control devices and specialized equipment like solar panels. API strongly encourages EPA to ensure the formal regulatory text creates a feasible and reasonable pathway for operators to comply.

- **EPA should streamline all recordkeeping and reporting.** Within this proposal, EPA is soliciting numerous comments regarding information on the number and types of records operators should maintain and report to EPA. EPA should continue to streamline both recordkeeping and reporting as it relates to these proposed requirements to include only the necessary information that will help assure compliance. Streamlining is especially critical for locations with existing sources as the cumulative impacts for tracking records are anticipated to be much larger than EPA estimates and will apply to hundreds of thousands of locations across the U.S. For some sources, EPA has described requiring records and potential reporting of information that does not link directly to emission controls or affected facilities, which API does not support. We acknowledge and appreciate EPA's streamlining of recordkeeping and reporting in the 2020 Technical Rule updates and support the inclusion of provisions such as these which maintain environmental control standards and assure compliance with less administrative burden.

- **EPA should grant equivalency for state programs across emission sources for NSPS OOOOb.** Given EPA has described many requirements that are consistent with those at the state level (e.g., CO, NM, and CA), EPA should allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb where it is appropriate to do so for LDAR and other emission control provisions.

As explained in Comment 11.1, when using the terms "proposal" or "standards" in these comments it does not constitute a "proposed rule" or "emission standard" for purposes of triggering applicability under CAA § 111(a)(2).

2.0 PNEUMATIC CONTROLLERS

Due to the critical nature of pneumatic controllers for safety and operation of oil and gas facilities, we offer the following comments for EPA's consideration in crafting requirements that provide adequate flexibility for solutions to reduce pneumatic controller emissions. Unfortunately, there is not a "one-size fits all" solution, and EPA should allow an array of options for reducing pneumatic controller emissions.

Some specific technical challenges with EPA's described proposal for use of "zero-emitting" controllers which must be addressed under both NSPS OOOOb and EG OOOOc include:

- issues with facilities securing adequate electric grid power (as described in Comment 2.5);
- potential creation of net emissions increases due to on-site natural gas or diesel fired generators (as described in Comment 2.6);
- reliability risks associated with unproven solar-power systems including battery storage (as described in Comment 2.7); and
- hiring or training of personnel with expertise in the installation, use, and maintenance of electronic controllers, which will likely need to be done by a licensed electrician.

2.1 EPA should re-evaluate the proposed standards for pneumatic controllers at both new and existing facilities.

We support the concept of moving towards non-emitting controllers for the collection of pneumatic devices located at completely new construction sites provided an array of control options are allowed (refer to Comment 2.2) and there is a sufficient phase-in period (refer to Comment 2.11). However, we are unable to assess the feasibility of proposed requirements for modified sites because EPA has not delineated how modification of controllers is determined given the new control strategy proposed under NSPS OOOOb. We offer our solution in Comment 2.4.

For existing pneumatic controllers, we believe it is most appropriate to focus on conversion to non-emitting controllers at facilities with the largest number of controllers and with readily accessible grid power. We do not believe EPA should require a complete phaseout of properly functioning low bleed and intermittent controllers at existing facilities, as discussed further in Comments 2.9 and 2.10.

2.2 EPA should allow for the use of “non-emitting” pneumatic controllers versus “zero-emitting” pneumatic controllers.

While the change in terminology may appear subtle, EPA should amend its proposal to allow the use of “non-emitting” instead of “zero-emitting” controllers and allow for various technologies to achieve “non-emitting” status including the option of routing certain controllers to an existing combustion device if it is technically feasible to do so.

Even with this additional flexibility to route controllers to a combustion device, operators will need to evaluate the design and functional needs of the equipment at each site and determine the most appropriate path forward for achieving the “non-emitting” threshold defined for controllers. In remote locations without access to grid power, operators may require an approach that includes multiple solutions to achieve a “non-emitting” standard.

EPA should acknowledge and allow a more flexible approach for reducing emissions from pneumatic controllers for new and modified locations than what has been initially described in the proposal. Multiple options to reduce emissions include the following:

- pneumatic controllers driven by compressed instrument air,
- electric controllers,
- mechanical controllers, and
- routing natural gas controllers to a process, sales line, or combustion device.

2.2.1 State precedents allow flexibility in control options.

Colorado allows all options mentioned above and describes them as “non-emitting” in 5 CCR Regulation 7, Part D, Section III.

> *III.B.10. (State Only) "**Non-emitting Controller**" means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.*
>
> *III.B.12. (State Only) "**Routed Pneumatic Controller**" means a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.*

The proposed New Mexico Oil and Gas Sector Ozone Precursor Pollutants Rule[1] (Proposed 20.2.20.7 January 20, 2022) also uses the term "non-emitting controllers" to describe all these options which API prefers to "zero-emitting".

> *"**Non-Emitting Controller**" means a device that monitors a process parameter such as liquid level, pressure, or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.*
>
> *"**Pneumatic controller**" means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) and sends a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.*
>
> *"**High-Bleed Pneumatic Controller**" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.*
>
> *"**Low-Bleed Pneumatic controller**" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.*
>
> *"**Intermittent pneumatic controller**" means a pneumatic controller that is not designed to have a continuous bleed rate but is designed to only release natural gas above de minimis amounts to the atmosphere as part of the actuation cycle.*

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[1] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

> *"**Routed Pneumatic Controller**" means a pneumatic controller of any type that releases natural gas to a process, sales line, or to a combustion device instead of directly to the atmosphere.*

2.3 Under NSPS OOOOb, EPA should consider amending the affected facility definition to be the collection of pneumatic controllers at a well site or compressor station.

In the 2012 and 2016 NSPS for the oil and gas sector, EPA defined the affected facility as a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh (also referred to as a high-bleed controller). Given the control option was to use a device of similar function with a lower bleed rate, a single controller being the affected source was a technically feasible approach to reduce emissions.

In this proposal, EPA is fundamentally changing the control strategy for pneumatic devices, such that the control option occurs for the collection of pneumatic controllers at a facility by requiring design of the pneumatic system to be non-emitting. Converting a single pneumatic controller to a non-emitting device typically requires that all controllers at the facility be converted to non-emitting devices. Even by EPA's own cost analysis, EPA assumed the control options would occur at the site level and would not occur for an individual controller. Therefore, API suggests that EPA re-evaluate the definition for natural gas driven pneumatic controller affected facility to be considered as a collective versus an individual controller under NSPS OOOOb.

API is supportive of the use of non-emitting controllers for newly constructed well sites, tank batteries, and compressor stations. We offer the suggested affected facility definition based on current NSPS OOOOa language as follows:

> *Each pneumatic controller affected facility ~~not located at a natural gas processing plant~~, which is the collection of natural gas driven pneumatic controllers that vent to the atmosphere located at a well site, centralized production facility, or compressor station.*

2.4 Under NSPS OOOOb, modification for the collection of natural gas driven pneumatic controllers should be defined similar to what EPA has defined for the collection of fugitive components at well sites and compressor stations.

As mentioned, the new proposed control standards under NSPS OOOOb are designed to occur at a site or system level and not by individual controller. Therefore, installing a single pneumatic controller at an existing surface site should not trigger the requirement for retrofitting all controllers to the non-emitting standard. Given the fundamental change in control strategy, EPA must re-evaluate the affected facility definition for controllers and what actions constitute a modification at the site level (and not controller level).

As with any equipment, pneumatic controllers break from time to time and must be replaced. To manage controller maintenance and more easily determine if a modification has occurred, API requests that a modification to a collection of natural gas driven pneumatic controllers be defined similar to how EPA has defined modification in 40 CFR 60.5365a(i) and (j) for well sites, tank batteries, and compressor stations which is summarized as follows:

Collection of natural gas driven pneumatic controllers located at	**Actions that Trigger Modification for Pneumatic Controllers to Non-emitting**
Well Site	▪ A new well is drilled at an existing well site; ▪ A well at an existing well site is hydraulically fractured; or ▪ A well at an existing well site is hydraulically refractured.
Centralized Production Facility	The above actions listed under well site occur at the tank battery or a well site that sends production to the tank battery.
Compressor Station	▪ An additional compressor is installed at a compressor station; or ▪ One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station.

Under the above outlined concept, when a modification occurs, the operator would be required to retrofit the collection of pneumatic controllers at the well site, tank battery, or compressor station to non-emitting controllers. As described earlier, a non-emitting controller could include a natural gas controller routed to a process, sales line, or combustion device. Sufficient time will be required to phase-in these retrofits after NSPS OOOOb is finalized.

2.5 Technical Challenges with Grid Power Requirements

2.5.1 Access to grid power must be limited to commercially available onsite connections with sufficient and reliable power.

EPA must clarify that "access to power" means that commercial line power is available onsite, sufficient to cover the power/capacity requirements of the non-emitting pneumatic controller design of the facility, and which provides reliable and consistent coverage. It is not always logistically feasible to electrify a location from the grid due to issues outside of an owner/operator's control. These challenges include right-of-way (ROW) issues for placement of power lines, a landowner's right to not install power lines on their property[2], and/or distance from an available power line that contains sufficient power and capacity to connect the facility. Therefore, EPA must be clear that running new commercial power lines to any site is not EPA's intent given the practical, technical, and cost challenges this would cause at large scale implementation across the country.

2.5.2 Sufficient Volume and Quality of Grid Power

Equipment power requirements at oil and gas facilities are quite varied, ranging from instrumentation at a single well pad needing approximately 35 watts to operate all the way up to approximately 2,000 kilowatts at larger sites running more equipment on electrical power. The power demand required to operate equipment determines if single phase power (household) is adequate or if three phase power (industrial) is necessary. Single phase low volume power may be accessible in certain areas, but three phase industrial wattage levels may not be available. Furthermore, even with accessibility, there may not be sufficient levels to run a given site or field. Due to the challenges around the development of adequate power supply to remote locations and the temporary nature of some areas of oilfield demand, many sites are supplied by onsite generation through produced natural gas as a motive source or natural gas generators.

2.5.3 Right-of-Way Issues

The largest challenge to oil and gas operations having grid power is obtaining ROW access for power lines. On private lands, landowners may choose to never allow ROW, particularly on large ranches. On federal lands, the current lead time for installation is typically between 6 months up to 2 years. It should be noted that the longest lead times have been experienced on federal lands controlled under the Bureau of Land Management (BLM). Additionally, as the Administration pursues updates to other regulatory requirements, such as environmental reviews as proposed by the Council on Environmental Quality in the Phase 1 NEPA revisions, these challenges may be exacerbated by expanding requirements and protracted timelines. A Memorandum of Understanding (MOU) may be needed between the EPA and BLM and state land offices to expedite approval of ROW for grid power.

2.5.4 Even if logistically possible, it is unlikely to be cost effective to access off-site grid power to convert a site to non-emitting controllers.

Even without the foregoing concerns, the cost and timing to obtain grid access can be prohibitive when it is not readily accessible onsite. Since EPA did not include nor consider costs for installing new power lines in its cost benefit analysis, it is assumed EPA did not intend to require operators to run new commercial power lines in order meet proposed control requirements for pneumatic controllers. We support EPA in this approach, as this would not be cost-effective and would cause other environmental

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[2] In some states, the utility provider can implement eminent domain, but production companies would not and do not have this authority. Other states, such as North Dakota, do not have eminent domain authority.

disbenefits (e.g., potential land disturbance) in pursuit of eliminating emissions from a small number of ancillary controllers.[3]

As a point of reference, experiences with API member companies suggest an average estimated cost of approximately $200,000 per mile for installing an electrical line to a facility where one does not already exist. When this additional cost is considered for 1 mile of new power line and all other EPA assumptions remain, retrofit of pneumatic controllers is not cost-effective for small and medium model plants.

2.6 Emission reductions may be offset where a diesel or natural gas generator would be necessary.

There are numerous situations where operators legally cannot obtain grid power, where solar may not be a feasible option, or where an operator may plan for connecting to grid power, but delays occur. In these situations, operators will utilize a non-emergency natural gas or diesel generator to power a compressor instrument air system as the only option to achieve a non-emitting standard. This scenario could be true at either new or existing locations. The tradeoff in this situation is between creation of criteria pollutants and CO_2 from generators when other power sources are not available versus venting of methane.

According to input from API members, a natural gas-fired generator of approximately 200-hp would be needed to support reliable operation of a large instrument air system without grid power. Emissions from a generator this size are estimated to be 1.94 tons per year (tpy) of NO_X, 3.88 tpy of CO, 1.36 tpy of VOC, 0.12 tpy of PM_{10}, 0.14 tpy CH4 and 730 tpy of CO_2[4]. The generator emissions will have environmental impacts and offset the VOC and methane emission reductions from use of non-emitting pneumatic controllers.

2.7 Solar Power Technology Challenges

2.7.1 The long-term reliability of solar-powered technologies is still being evaluated.

Non-natural gas-driven pneumatic controllers include solar powered electric controllers and solar powered instrument air applications. For remote sites without grid access, some operators are piloting solar arrays with battery storage to power an instrument air system for pneumatic controllers. We are unaware of any operators converting to solar powered electric controllers at this time. While the technology seems promising, many of these solar systems have not yet been proven reliable for all

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[3] On page 8-21 of EPA's Technical Support Document issued with this proposal, EPA states "Since this electrical supply is assumed to be on the site irrespective of the electronic controllers at the site, the costs of the power supply were not included in the analyses of emission reductions and costs for electronic controllers."

[4] Emissions were based on AP 42, Vol. I, 3:2, applicable NSPS JJJJ limits, and 40 CFR 98, Subpart C for a 201-bhp natural gas engine operating 8,760 hours per year. Methane estimated based on 40 CFR 98, Subpart C.

remote locations or facility designs and are not ready for deployment across the country at the large-scale EPA's proposed rules would require. In 2014, EPA stated "solar-powered controllers can replace continuous bleed controllers in certain applications but are not broadly applicable to all segments of the oil and natural gas industry."[5]

For many sites, a solar-powered pneumatic controller system presents significant design challenges to overcome, including, but not limited to, the following:

- Large-scale solar applications have not yet been tested in winter months when there is more cloud coverage, increased snow cover, and less sunlight in more northern locations (Colorado, North Dakota, Idaho, Wyoming, etc.). Evidence suggests that even during periods without direct radiation, substantive energy is supplied to solar panels through ground reflection and diffused radiation. However, without adequate field-testing, it is probable that supplemental power via natural gas or diesel -powered generators could be required during winter months and/or severe weather events. This is necessary to ensure a continuous power supply, and, thus, controlled operation. Interruptions within the control system pose safety risks to operators and can damage processing equipment, which could potentially lead to excess environmental emissions associated with equipment malfunctions.

- As discussed in Comment 2.7.3, at temperatures at or below -20°C (-4°F), solar battery capacity is decreased to 50%. This reduces the overall life of the solar battery, which impacts the overall reliability and lifespan of the system. Further, if low temperatures cause freezing, an interruption to power supply for the pneumatic controller system will occur.

- For many sites, the impact to photovoltaic performance based on the level of particulate accumulation on the solar panel(s) is not well documented. This is important for remote, unmanned sites as challenges associated with properly cleaning the panels are encountered. The decrease in energy loss due to particle accumulation greatly varies based on several factors including site location, surrounding soil type, dust characteristics, and other surrounding air pollution.[6] One study suggests that in the U.S. over a 3-month period, up to 4.7% solar capacity is lost due to particulate accumulation on solar panels.[7]

2.7.2 Many solar system packages in use do not feature turnkey solutions available for mass installation and implementation.

Technology provided by certain vendors was referenced in the Carbon Limits study published in 2016,[8] which EPA relied upon in its cost effectiveness analysis. Industry representatives reached out to at least

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[5] Oil and Natural Gas Sector Pneumatic Devices, Review Panel, USEPA, OAQPS, 2014: https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf.

[6] Renewable and Sustainable Energy Reviews, Volume 59, June 2016, Pages 1307-1316. Renewable Power loss due to soiling on solar panel: a review, Mohammad Reza Maghami.

[7] Hottel, H, and Woertz, B. Performance of flat-plate solar-heat collectors. United States.

[8] Carbon Limits. *Zero emission technologies for pneumatic controllers in the USA.* August 2016

one of the vendors within the last six months to find out how much deployment there has been of these solar systems and electric controllers. The vendor indicated that in the past 10 years, they have conducted 200 retrofits and 300 new installs. Currently, the vendor projects it can only service approximately 200 installs per year.[9] Additionally, operators are already experiencing 6 to 12-month lead times for solar packages. The proposed rules will only exacerbate demand, increase costs, and increase pressure on the supply chain.

2.7.3 Additional technical challenges experienced with battery storage and capabilities prohibit use in some facility locations.

Remote oil and gas site applications for solar installations typically require up to 1,600 watt, 24 VDC capacity with a common battery type being an 8G8D gel cell (number of batteries required per application can range from 2 to more than 10). The exact number of solar sets is greatly variable based on site-specific requirements.[10] When sizing the solar system, in addition to site-specific requirements, the temperature profile of the site also impacts the type, number, and capable performance of batteries for solar packages. For example, the Deka 8G8D battery has an operating temperature range from -30°C (-22°F) to 50°C (122°F); however, the optimal operating range is above 0°C (32°F) because cold temperatures increase the internal resistance of a battery, thereby reducing capacity. The standard capacity rating of this example battery is based on each cell having an electrolyte temperature of 20ºC (68ºF).[11] At temperatures below the nominal rate, the battery's effective capacity is reduced, and the time to restore the battery to full charge is increased exponentially with decrease in temperature. Figure 1 displays the relationship between battery capacity and temperature for a Deka 8G8D solar battery; at -20°C (-4°F), battery capacity is decreased to 50%. Table 1 shows six states with significant oil and gas operations where temperatures fall in the range for reduced solar battery capacity during winter. Further, it is noted that the recent unprecedented winter storm in Texas (February 2021) saw a low temperature of -27° (-16°F).[12] Unfortunately, during severe weather days including snowstorms, solar panels are often not receiving sunlight and battery power is being used. Sufficient battery power at a high charge is needed for at least 7-10 days without sun. If the decreased sunlight lasts for too many days, batteries can freeze. Solar batteries in the oil field often freeze and stop functioning, particularly in areas where temperatures can drop to -40ºC (-40ºF).

On the other hand, extreme heat can also negatively affect battery performance and reliability. Though temperatures above 25ºC (77ºF) will slightly increase capacity, the potential of self-discharge and reduced battery life is increased. Further, as temperatures rise, any cycle life loss due to operating at higher temperatures is not recoverable. During extreme heat events, such as those experienced in Texas

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[9] Joint Industry Work Group comments submitted to CDPHE https://drive.google.com/drive/folders/1yXOxLue7DqPFutsxbq6SeThCMhc5S7DU

[10] Example of solar installations at oil and gas sites: https://www.scadalink.com/products/remote-power/industrial-solar-panels/.

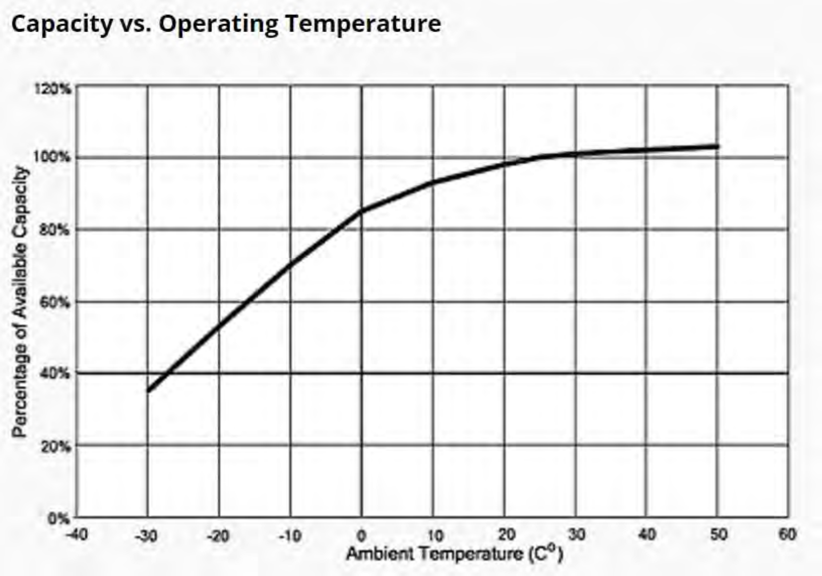
[11] Deka battery specifications: https://www.solarelectricsupply.com/solar-components/solar-batteries/gel-batteries/deka-8g8d-solar-batteries

[12] Feb. 2021 Texas Winter Storm Details: https://www.weather.gov/media/ewx/wxevents/ewx-20210218.pdf.

and Louisiana, overheating of the battery is possible. In this scenario, the battery lifespan can be shortened, or the battery can be completely damaged.

For nonessential equipment, losing power is not a concern. Pneumatic controllers are critical for safe operations. Due to the temperature profile of the key states in play, current solar battery performance may be too unstable for the operation of pneumatic controllers.

Figure 1. Capacity vs. Operating Temperature for Deka 8G8D Solar Battery



Source: https://www.solarelectricsupply.com/solar-components/solar-batteries/gel-batteries/deka-8g8d-solar-batteries

In addition to concerns related to temperature, the type and number of batteries required for remote industrial sites (e.g., gel lead acid batteries and absorbed glass mat (AGM) batteries) are on average higher in cost as compared to household solar panel systems.

Table 1. Winter Temperatures for some States with Oil and Gas Operations

State	Average Winter Temperature[13]		Record-Low Temperature[14]	
	°C	°F	°C	°F
North Dakota	-4	25	-51	-60
Texas	0	32	-30	-22
New Mexico	-16	3	-45	-49
Oklahoma	0	32	-35	-31
Colorado	-9	16	-52	-62
Alaska	-28	-18	-62	-80

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[13] Average temperatures based on 30-year records, for average of December – February: https://www.usclimatedata.com/climate/united-states/us

[14] Record-low temperatures: https://ggweather.com/climate/extremes_us.htm.

2.8 Review of EPA's Cost Benefit Analysis for Converting Pneumatic Controllers to Non-Emitting

2.8.1 EPA based their model plant analysis on incorrect assumptions.

Based on blinded data collected from API member companies by a third-party, EPA has underestimated the costs and overestimated the benefits for converting pneumatic controllers to non-emitting. A summary of EPA cost assumptions is provided in Table 2.

Table 2. Summary of EPA Estimated Capital Cost Assumptions for Pneumatic Controllers

EPA Model Plant Reference	EPA Estimated Capital Cost for Grid Power Electric Controllers[a]	EPA Estimated Capital for Solar Power Electric Controllers[b]	EPA Estimated Capital Cost for Grid Power Electric Instrument Air System
Small (4 controllers)	$25,494	$28,171	Not estimated
Medium (8 controllers)	$45,889	$51,242	Not estimated
Large (20 controllers)	Not estimated	Not estimated	New: $95,602 Existing: $127,469

a. EPA costs included the costs of controllers ($4,000 each) and a control panel for grid connection ($4,000). EPA also included installation and engineering estimates based on 20% of equipment costs, which equated to $4,420 for small model plants and $8,040 for medium. EPA did not include any annual operating or maintenance costs within their assumptions.

b. For solar electric controllers, EPA costs included cost of electric controllers ($4,000 each), a control panel ($4,000), 140 W solar panel ($500), and 100 Amh batteries ($400 each). EPA also included installation and engineering estimates based on 20% of equipment costs, which equated to $4,000 and $7,200 for the small and medium model plants, respectively. EPA did not include any annual operating or maintenance costs within their assumptions.

The variation in the costs estimated by EPA with API member costs is centered on incorrect assumptions by EPA that companies will use grid power or solar based systems to power electric controllers. API members have converted natural gas driven pneumatic controllers to compressed instrument air systems powered by the grid (when accessible) or natural gas generators and are only in the initial phases of testing the reliability of solar based instrument air systems.

Costs associated with a typical instrument air system include a regenerative dryer, inlet filter, tank to store compressed air, insulated enclosure for the compressor and dryer, junction box, controllers for the compressor system, and voltage boosters. Additional costs for solar based systems would include higher cost gel or AGM batteries, sufficient number of batteries, and higher numbers of solar panels required in areas of less sunlight such as for Wyoming and North Dakota. Additional costs associated with the use of natural gas or diesel generators to power instrument air systems might also include monthly rental fees. All instrument air systems typically require annual maintenance at a cost of between $2000 and $4000 per year. Installation of non-emitting controllers also requires shutting-in the well or facility, an additional cost which does not appear to be accounted for in EPA's cost analysis. Cost estimates based on our blinded member survey are provided in Table 3.

Table 3. Average API Member Feedback regarding Capital Cost for Non-Emitting Technologies: Instrument Air Systems

Estimated Capital Costs for Various Sized Instrument Air Systems	Grid Power Instrument Air System[a,b]	Solar Power Instrument Air System	Natural Gas Generator Instrument Air System
Small to Medium	$51,000	Not estimated	$60,000
Medium to Large	$80,000		$110,000
Multi-Well Site, Central Production Facility or Compressor Station (>100 controllers)	$143,333	$250,000[c]	$207,250

a. Assumes the facility has existing grid power including a step-down transformer already in place and converts to an electric power instrument air system.
b. If grid access is not available, average costs to run a new power line is an additional $200,000 per mile.
c. This includes the cost of the solar panels, batteries and conversion to electric controllers and based on existing facility design with actual production values and local meteorological conditions.

Additionally, member experience has indicated that EPA's distinction between the small and medium model plant is incorrect when it comes to cost variation since a site with either 4 or 8 controllers would be considered a relatively small facility with minimal equipment. Some multi-well sites, central production facilities and compressor stations may contain 100-200 controllers. These larger facilities are typically the types of facilities that operators have been successful in retrofitting pneumatic controllers to non-emitting in a cost-effective manner by placing the investment of retrofit on the facilities with the most controllers. It is not economic and sometimes not feasible to convert pneumatic controllers to instrument air, particularly at older facilities with less wells and lower production. Retrofitting becomes even more challenging and uneconomic in instances where the wellhead is not co-located with the facility, as each remote wellhead would need its own power generation.

Additionally, some members have found that certain pneumatic controllers can be routed to an existing combustion device for a nominal investment. Like pneumatic pumps, there are challenges with this approach as not all existing locations may have an existing combustion device and not all types of controllers at a facility can be routed to an existing combustion device.

2.8.2 Emission Factors Applied for Intermittent Controllers

API appreciates EPA utilizing emission factors from API's *Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas*.[15] However, we believe that the use of the average intermittent pneumatic device vent rate is incorrect in this application. In this same proposal EPA is proposing to include intermittent controllers within the monitoring framework by including them in the definition of fugitive component and considering their emissions in the determination of a site's potential methane emissions. Under this proposal, any intermittent device would be monitored routinely and repaired or replaced if malfunctioning, so the more appropriate emission factor that should be utilized is 0.28 scf whole gas/controller-hour and not the average emission factor of 9.2 scf whole gas/controller-hour as documented in API's 2021 GHG Compendium Table 6-15.[16] The average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or where the monitoring status is unknown. The normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program.

Emissions savings from this approach (i.e., the emission reduction benefit from fixing improperly functioning controllers) is currently already captured in EPA's cost-effective analysis for the proposed leak detection and repair (LDAR) requirements. This approach achieves nearly a similar level of emission reduction for much less investment by operators. This is especially true when converting a single existing high-bleed controller with a properly functioning intermittent controller that is part of a company's LDAR program. Furthermore, if an existing facility only contains properly functioning intermittent controllers confirmed through an LDAR program, then the cost effectiveness evaluation never becomes cost-effective for any amount of controllers even assuming EPA's own cost assumptions.

When we review EPA's cost effectiveness analysis, updating the intermittent controller emission rate to the properly functioning emission rate reduces the baseline emissions for each model plant significantly, which directly reduces the potential emission reductions. When coupled with the fact that EPA underrepresented the actual costs for conversion to non-emitting technologies, the cost-effectiveness for the proposal under NSPS OOOOb and EG OOOOc quickly becomes not cost-effective either for methane or VOC with or without savings.

In Attachment C, we evaluated the minimum number of controllers that would be cost effective to retrofit to an instrument air system powered by grid power or a natural gas generator, using the minimum costs listed in Table 3. The results indicate that for a facility containing low bleed controllers and properly functioning intermittent controllers, it would only be cost effective to retrofit if there were

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[15] API's Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas." Presented on November 7, 2019 in Pittsburg PA by Paul Tupper.

[16] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

at least 15 to 30 controllers, depending on the single/multi-pollutant, with or without savings approach, that EPA analyses.[17]

2.8.3 Retrofit of a single low bleed or intermittent controller is not cost-effective.

The cost effectiveness associated with converting a single low bleed or intermittent controller to a non-emitting controller using solar or electric power is summarized in Table 4. The results indicate it is not cost-effective to retrofit a single low bleed or intermittent controller. This analysis relied on controller system costs as provided in EPA's pneumatic controllers costs and emissions workbook for a small model plant. As we describe above, an API member survey suggests minimum costs are at least double the costs estimated by EPA for small model plants, which would best reflect the minimum costs associated with retrofitting a single controller. Based on this review, API suggests EPA exempt facilities from the non-emitting controller standard under NSPS OOOOb and EG OOOOc if there is only a single low bleed or intermittent controller present.

Table 4. Cost Effectiveness Estimates for Retrofitting a Single Low Bleed or Intermittent Controller

Retrofit Scenario as Outlined in EPA's Cost Effectiveness Analysis	Cost Effectiveness ($/ton) Without savings		Cost Effectiveness ($/ton) With Savings	
	VOC	Methane	VOC	Methane
Single low bleed to solar	$28,312	$7,870	$27,659	$7,689
Single low bleed to electric grid	$25,621	$7,122	$24,969	$6,941
Single properly functioning intermittent to solar[a]	$262,893	$73,078	$262,240	$72,896
Single properly functioning intermittent to grid[a]	$237,912	$66,134	$237,260	$65,952
Single unknown intermittent to solar	$8,001	$2,224	$7,349	$2,043
Single unknown intermittent grid	$7,241	$2,013	$6,588	$1,831

a. Emission factor for properly functioning pneumatic controller as referenced in Table 6-15 in the Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry.[18]

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[17] To estimate baseline emissions, we assumed a mix of controllers onsite of 30% low-bleed and 70% intermittent, which is consistent with the breakdown of controller types reported to EPA for the 2020 calendar year pursuant to 40 CFR Part 98, subpart W. EPA was incorrect to assume a high bleed pneumatic controller within their model plant analysis as the count of high bleed controllers is only 1% for the production segment and 3% for the gathering and boosting segment based on the 2020 Subpart W data (refer to Attachment A, Table C-1). We also applied the properly functioning emission factor from Table 6-15 of API's GHG Compendium based on the comments offered herein.

[18] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

2.9 EPA should not require a complete phaseout of properly functioning intermittent and low bleed natural gas driven pneumatic controllers at existing facilities.

Many existing well sites are low producing wells that could be close to end-of-life of their production cycle and may only contain a limited number of controllers. The complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production. Furthermore, existing well pads may have sizing constraints for the proper placement (due to safety and other permitting constraints) of control systems, compressors that must sit outside of classified areas, generators, or solar panels. For these reasons, the state regulations EPA cites in support of this proposal, including Colorado and the current proposed version of regulations pending in New Mexico[19], do not require all existing controllers to be retrofitted as EPA has proposed. Colorado's regulations, as well as the draft regulations pending in New Mexico, concluded this is unwarranted as controller retrofit is not cost-effective nor technically feasible for many facilities.

2.10 For EG OOOOc, retrofit to non-emitting controllers should be based on the availability of onsite grid power and a minimum number of gas-driven pneumatic controllers. Absent feasibility to retrofit, the use of continuous low bleed and intermittent natural gas controllers should be allowed and covered in an operator's existing LDAR monitoring program to monitor proper functioning.

For existing locations, API supports EPA's proposal to retrofit to non-emitting controllers, as we define in Comment 2.2, where the following criteria are met:

a) There are at least 15 controllers at the well site, central production facility, or compressor station; and

b) There is access to sufficient and reliable grid power onsite.

If the above criteria are not met, then any high-bleed natural gas driven controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company's LDAR monitoring program to monitor proper functioning. This approach is similar to and based on the rationale for EPA's proposed requirements for pneumatic controllers at sites in Alaska without grid access.

Refer to Comment 2.8 and Attachment C for API's determination of the minimum number of controllers required for retrofit to be cost effective.

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[19] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

2.11 Adequate implementation time must be provided for pneumatic controller requirements under both NSPS OOOOb and EG OOOOc.

For modified sites (as outlined in Comment 2.4) and existing source retrofits, operators will need sufficient time for identifying devices for replacement or retrofit, designing and engineering systems, planning, budgeting, purchasing equipment, contracting labor, scheduling the work required and prioritizing equipment for retrofit. To retrofit a facility with instrument air, an engineer first verifies that adequate power is available and then applies for necessary permits, which takes approximately 60 days to acquire (if approved). During construction, an instrument air header and compressor skid must be added to the facility. The air compressors must sit outside of classified areas and therefore, some older reclaimed facilities may not have space to add necessary equipment. The gas lines, instruments, and tubing must be inspected to verify that they do not have any damage from extended use of wet gas. All lines, tubing and instruments with damage must be replaced. If there is not power at locations, generators will have to be set to power the air compressor. One retrofit project can take upwards of 4 months to complete from initial planning to full implementation.

As mentioned previously, there is a 3-year phase-in precedent that has been established for the oil and gas sector, which we believe is the minimum timing required for an appropriate phase-in of the pneumatic controller standard at existing locations. A more appropriate time period, given all of the existing sites in the U.S. and the implementation aspects outlined above, would be 5 years from the finalized rules/guidelines.

2.12 EPA must confirm that emergency shutdown valves or devices are not considered pneumatic devices.

In Section XI.C.1 of the preamble (86 FR 63179), EPA is soliciting comment on whether owners/operators believe that maintaining an exemption based on functional need similar to those finalized in NSPS OOOO and OOOOa is appropriate, and if so, why.

Emergency shutdown devices (ESDs) should remain exempt from the proposed pneumatic controller requirements. An ESD is designed to minimize consequences of emergency situations and will only emit in certain isolated circumstances, such as if a well must be shut in. A large change in pressure is required to actuate an ESD, which may not be deliverable in a sufficient time by a compressed air or electric controller. Furthermore, if power is lost, these devices must still be able to function. ESDs are rarely activated, and their emissions impact is minimal, but their functional need is necessary and critical to safe operations. We also note that both the current version of the proposed rule in New Mexico and finalized regulations in Colorado offer similar exemptions for ESDs.

2.13 The pneumatic controller requirements should be limited to stationary sources.

Pneumatic controllers located on temporary or portable equipment should be allowed to operate as low-bleed or intermittent as needed for proper functioning of the temporary equipment. Connecting temporary controllers into the grid or routing to a combustion device requires significant engineering design, if these options are even available. Non-emitting requirements are not justified for short term controller usage related to a non-stationary source, and exemption of controllers on temporary equipment is consistent with state regulations proposed in New Mexico[20] and finalized in Colorado[21]. EPA should also make it clear that the requirements for pneumatic controllers are not applicable during drilling or completion.

3.0 APPENDIX K PROTOCOL FOR USE AT REFINERIES AND GAS PROCESSING PLANTS

It is API's understanding that the proposed Appendix K protocol was intended to streamline use of optical gas imaging (OGI) technology at refineries and other similar large process facilities such as gas processing plants, as an alternate to M21. In this regard, API supports EPA's development of Appendix K as the ability to use OGI technology provides flexibility and the potential to reduce equipment leak emissions at a lower cost than traditional methodologies.

However, API believes significant modifications to the proposed Appendix K are necessary before it could effectively be implemented for use across downstream oil and gas facilities, gas processing plants, or other process industries. API's recommended changes are intended to proactively address concerns that:

1) the proposed requirements will result in difficulty in finding and retaining adequate numbers of qualified senior OGI operators;
2) the monitoring, training and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and
3) the ownership of various requirements, particularly the recordkeeping requirements, are unclear and unnecessarily burdensome.

API's recommended changes also aim to make the Appendix K requirements more straightforward and efficient. Our recommended modifications to Appendix K are detailed in Attachment A and a suggested redline of Appendix K is provided in Attachment B.

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[20] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

[21] https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view

4.0 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

4.1 Appendix K is inappropriate for use at production facilities, gathering and boosting compressor stations, and transmission compressor stations. OGI monitoring protocols for these facilities should continue to be based on NSPS OOOOa standards.

Appendix K is inappropriate and should not be required for upstream well sites, centralized production facilities, gathering and boosting compressor stations, and transmission compressor stations given. It is impractical for operators to implement the detailed and unnecessarily time-consuming requirements of Appendix K given the hundreds to thousands of well sites and compressor stations to monitor, the geographic dispersion of these facilities and the lack of on-site resources.

Key differences between production facilities and compressor stations versus refineries and gas plants include:

- **Upstream and midstream facilities are smaller, less complex, and have fewer regulated emission components.** A typical well pad size is up to a few acres versus up to thousands of acres for a refinery and well sites contain tens to hundreds of components versus tens of thousands of components at a refinery.
- **There are many more well sites and compressor stations.** There are hundreds of thousands of well sites and compressor stations in the U.S. versus approximately 129 refineries and approximately 500 gas plants.
- **Most new and existing well sites, centralized production facilities, and compressor stations are unmanned sites.** Additionally, these sites are often in remote locations**.** Refineries and gas plants have onsite LDAR personnel.

The following elements of Appendix K make it impractical to implement at upstream and midstream facilities other than gas plants.

- **Appendix K does not appear to support all potential OGI camera deployment platforms, such as drones or fixed continuous monitoring cameras, through its frequent use of the term "handheld".** Current NSPS OOOOa requirements allow a variety of OGI deployment platforms. EPA has also not demonstrated why a different OGI camera deployment would affect the ability of the OGI camera to detect and therefore require development of a separate operating envelope for each OGI camera deployment platform.
- **The lack of in-house personnel that qualify under the currently proposed Appendix K training requirements may force operators to rely on third-party contractors.** A reliance on third-party contractors could result in more emissions from delays in completing leak repairs, given a third-party contractor may not be trained or allowed by the operator to attempt an immediate leak repair. Under NSPS OOOOa programs, some companies' in-house OGI camera operators are allowed to make a first repair attempt upon leak detection.

- **The OGI camera performance specifications in Appendix K are different from those in NSPS OOOOa, reflecting the differences in the two types of sources these two methodologies address.** A comparison of these requirements is presented in the following table.

Appendix K	NSPS OOOOa
An OGI camera meeting the following specifications is required: The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition.	Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.
An OGI camera meeting the following specifications is required: The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr) and butane emissions of 18.5 g/hr at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less.	Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr from a quarter inch diameter orifice.

EPA has not demonstrated that these more stringent requirements are more effective at detecting leaks at well sites, centralized production facilities, and compressor stations. NSPS OOOOa camera specifications have been demonstrated as feasible by EPA testing and in the field. Existing cameras have not been tested and certified to meet the proposed Appendix K specifications. These more stringent Appendix K requirements will require retesting of existing OGI cameras and if the camera does not meet these requirements, require operators to purchase a new OGI camera, which is an additional cost not considered in EPA's cost analysis.

- **The "operating envelope" in Appendix K adds impractical requirements for viewing distance, delta-T, and wind speeds beyond NSPS OOOOa requirements.** NSPS OOOOa already requires procedures for *"determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained", "how the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions", and "determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold."*[22] The Appendix K operating envelope requirements are overly burdensome and may not result in

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[22] 40 CFR 60.5397a(c)(7)

more effective OGI surveys; the current NSPS OOOOa requirements allow the flexibility to conduct effective OGI surveys under the variety of conditions encountered at well sites, centralized production facilities, and compressor stations.

- **The dwell time and break requirements in Appendix K are overly complicated, particularly for well sites, centralized production facilities, and compressor stations, where the density of fugitive emission components (number of components to view in each area) is less than for a refinery or gas plant.** These dwell time and break requirements would double or triple the time required for an OGI survey and have not been demonstrated to be more effective at detecting leaks. One company estimates that 40 or more hours would be needed to conduct an OGI survey of a single site following the Appendix K requirements. Unnecessarily long dwell times result in inefficient emission reductions and take time and resources away from other compliance activities with a greater environmental benefit. Furthermore, prescriptive dwell time is unnecessary and inefficient as an experienced camera operator will determine dwell time based on the circumstances that are occurring at the facility. Some components may require an extended dwell time, while other components may need less.

- **The 10-second video clips of leaks and tagging of leaking components required by Appendix K are overly burdensome to demonstrate compliance compared with the NSPS OOOOa requirement.** NSPS OOOOa requires that *"For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component, or the component must be tagged during the monitoring survey when the fugitives were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture)."*[23] EPA did not consider the additional cost of data storage for the 10-second video clips for a minimum of five years compared to a digital photograph. A digital photograph allows for identification of leaking components without tagging, which may not always be possible for elevated components or components in sour gas service due to safety considerations.

For these reasons noted above, API recommends that OGI requirements for new and existing well sites, centralized production facilities, and compressor stations be based on NSPS OOOOa requirements, not Appendix K.

4.2 EPA could strengthen standards finalized in NSPS OOOOa for using OGI in the production and transmission sectors and not apply the requirements in Appendix K.

As described in Comment 4.1, the provisions proposed in Appendix K are impractical for incorporation at upstream production facilities, gathering and boosting compressor stations, and transmission

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[23] 40 CFR 60.5397a (h)(4)(ii)

compressor stations and would make the use of OGI for leak detection technically impractical and result in inefficient emissions reductions. Operators have been performing OGI surveys at new or modified well sites and compressor stations according to NSPS OOOOa requirements since September 2015. As proposed, Appendix K goes beyond the current NSPS OOOOa requirements concerning performance specifications, "operating envelope", survey time, and records for leaking components and is impractical for operators to implement given the hundreds to thousands of well sites and compressor stations to monitor and the geographic dispersion of these facilities. Therefore, API urges EPA to retain NSPS OOOOa standards in the proposed regulatory text for NSPS OOOOb and EG OOOOc rather than applying the requirements of Appendix K for these sectors.

The NSPS OOOOa standards for OGI surveys could be strengthened within the NSPS OOOOb and EG OOOOc language, especially with respect to training for OGI camera operators. To help address this concern, we offer the following suggested OGI requirements for the upstream, gathering and boosting, and transmission sectors based on current NSPS OOOOa language in 40 CFR 60.5397a(c)(iv):

> *What fugitive emissions VOC and methane standards apply to the affected facility which is the collection of fugitive emissions components at a well site or centralized production facility and the affected facility which is the collection of fugitive emissions components at a compressor station?*
>
> *[text omitted for brevity]*
>
> *(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.*
>
> *[text omitted for brevity]*
>
> *(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.*
>
> *[text omitted for brevity]*
>
> *(vi) Training and experience needed prior to performing surveys. At a minimum, training and experience must include the elements in paragraphs (c)(7)(vi)(A) through (C) of this section.*
>
> *(A) Initial classroom or computer-based training including the items specified in paragraphs (c)(7)(v)(A)(1) through (8) of this section.*
>
> *(1) Key fundamental concepts of the optical gas imaging equipment technology, such as the types of images the equipment is capable of visualizing and the technology basis (theory) behind this capability.*
>
> *(2) Parameters that can affect image detection (e.g., wind speed, temperature, distance, background, and potential interferences).*

(3) Description of the components to be surveyed and example imagery of the various types of leaks that can be expected.

(4) Calibration, operating, and maintenance instructions for the optical gas imaging equipment used at the facility.

(5) Procedures for performing the monitoring survey according to the site monitoring plan, including the daily verification check; how to ensure the monitoring survey is performed only when the conditions in the field are within the established operating envelope; the number of angles a component or set of components should be imaged from; how long to dwell on the scene before changing the angle, distance, and/or focus; how to improve the background visualization; the procedure for ensuring that all regulated components are visualized; and documenting surveys.

(6) Recordkeeping requirements [assuming consistent with NSPS OOOOa streamlined improvements]

(7) Common mistakes and best practices.

(8) Discussion on the regulatory requirements related to leak detection that are relevant to the facility's optical gas imaging monitoring efforts.

(B) A minimum of 24 hours of surveys under the supervision of an experienced optical gas imaging equipment operator.

(C) Classroom or computer-based training refresher should be conducted no less than every three years. This refresher can be shorter in duration than the initial classroom or computer-based training but must cover all the salient points necessary to operate the equipment (e.g., performing surveys according to the monitoring plan, best practices, discussion of lessons learned throughout the year).

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

4.3 With our recommended changes regarding Appendix K applicability, API supports EPA's co-proposal applicability thresholds and frequencies for OGI monitoring at well sites and supports quarterly monitoring at compressor stations.

For new and existing locations, EPA has proposed the following OGI monitoring frequencies based on the site's potential to emit (PTE) for methane as summarized below:

Site Methane PTE	Co-Proposal Monitoring Frequency
> 0 to <3 tpy	One time
≥ 3 to <8 tpy	Semi-annual
≥ 8 tpy	Quarterly

API is supportive of EPA's co-proposal thresholds and frequency for well sites and centralized production facilities contingent on our recommendations related to the prospective application of Appendix K to these types of facilities.

4.4 The baseline emission calculation for site PTE should be streamlined.

EPA's proposal that site methane PTE calculation updates be required "every time equipment is added to or removed from the site" is too broad and would be overly burdensome since operators would constantly track equipment and perform calculation updates for hundreds to thousands of sites.

As proposed, well site operators must recalculate baseline emissions (which are comprised of a combination of population-based components and controlled storage tank emissions) whenever equipment is added or removed from the site without regard to whether the change results in increased emissions. This appears to convert this fugitive emission requirement into a site-specific inventory requirement. As such, the proposal is inappropriate and has not been demonstrated to be necessary for implementation of the proposed requirement.

Recalculation of baseline emissions is not warranted where equipment is removed because equipment removal will result at best in fewer emissions and at worst in no emissions change. Further, requiring baseline emissions recalculation each time equipment is added to a well site will require onerous tracking of facility changes with little or no environmental benefit. For example, adding one fugitive component to a facility would have no meaningful or significant change to the well site's potential fugitive emissions, yet EPA proposes this change warrants recalculation of baseline emissions. Further, EPA's approach assumes, without basis, that any addition of equipment will result in increased potential fugitive emissions (and specifically in increased potential fugitive emissions with the potential to result in a different inspection frequency).

Under the proposal (i.e., requiring inspections for facilities with baseline emissions above 3 tpy), in very few instances would changes at the facility result in a change in monitoring frequency. Even under the co-proposal (with an additional tier between 3 and 8 tpy), there are limited circumstances when changes at the facility would result in a change in the frequency of inspections. Baseline emissions recalculation should be required only for the qualifying modification events based on the NSPS OOOOa definitions of modification for fugitive emission monitoring per 40 CFR 60.5365a(i)(3) and (i)(4).

For well sites in the most frequent inspection frequency tier, EPA should not require baseline emissions recalculation because no increase in emissions will result in more stringent requirements. If an operator elects to conduct a recalculation to determine if they can reduce inspection frequencies, then operators may elect to do so.

The following includes additional clarifying improvements for when and how to assess the site PTE calculation.

- There must be adequate time to perform initial site PTE calculations at both new and existing locations and to phase-in the initial monitoring survey. These are new calculation assessments and larger operators will have hundreds to thousands of calculations to manage, document, and plan for monitoring. Adequate time following a qualifying modification event must also be provided for updating the site PTE.
- Operators should have the ability to opt-in to quarterly monitoring without any requirement to calculate site methane PTE.
- For obtaining more accurate site emission estimates, operators should be able to use automation, measurement, or state approved emission factors in addition to the specified method described by EPA in this proposal.
- Since OGI detects leaks, but does not measure leaks, EPA must make it clear that sites with emissions less than 3 tpy conduct the one-time leak survey and not be required to reassess the emission evaluation unless there is a qualifying modification event.
- The PTE calculations should be limited to stationary sources. The addition or removal of temporary equipment should not require updated site methane PTE calculations.
- The site PTE calculation should only include controlled storage tanks.

4.5 EPA's cost analysis erroneously assumes operators would not purchase an OGI camera.

As API pointed out in our December 4, 2015 comment letter on proposed NSPS OOOOa[24], EPA continues to exclude the cost of an OGI camera within the cost benefit analysis and assumes operators will only rely on third-party contractors to perform OGI monitoring. This incorrect assumption must be re-evaluated by EPA. As we stated in 2015, API survey responses collected by a third-party ranged from $90,000-$100,000 for an OGI camera. A conservative assumption would be to include the costs for at least a single OGI camera. Most companies own and operate numerous cameras because it takes a team of LDAR technicians to implement and manage an OGI monitoring program across hundreds to thousands of sites.

We also note that EPA failed to consider any additional administrative burden associated with updated requirements described in the proposed Appendix K, which would be significant.

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[24] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776)

4.6 The process for assessing the cause of equipment malfunctions and operational upsets should be streamlined with appropriate completion and reporting schedules.

EPA's proposal requires that an owner or operator must conduct a "root cause analysis" in the case of "a malfunction or operational upset of a control device or the equipment itself, where emissions are not expected to occur if the equipment is operating in compliance with the standards of the rule"(e.g., malfunctioning pneumatic controllers, unintentional gas carry through, or venting from covers and openings on controlled storage vessels) and also where an alternative screening event identifies a "large emissions event."

The specific term "root cause analysis" has other meanings in various regulations and in the oil and gas industry. Instead of using the term directly within NSPS OOOOb and EG OOOOc, we suggest the following description be used in its place as it targets what information and action should occur during the analysis:

> *"Identify the primary cause, and any other contributing cause(s), of a malfunction or operational upset of a control device or the equipment itself".*

We also suggest EPA streamline the recordkeeping and reporting of information related to the assessment.

4.7 Advanced leak detection technologies should be specified as an alternative BSER.

Using transparent and accepted models, alternate technologies can be demonstrated to be as effective as OGI and M21 in emission reductions and should be considered BSER. API supports EPA's inclusion of an option to utilize alternate methane detection technologies, but changes are needed to provide increased flexibility in their implementation. Discussed below are our suggestions to create a more workable framework.

4.7.1 EPA should create a functional and transparent framework for using alternate leak detection technologies.

API supports development of a framework that drives innovation and lowers the economic hurdles typically experienced with new technologies. Key considerations for such a framework include:

- **A minimum detection threshold of 10 kg/hr restricts operators' flexibility in selecting appropriate alternate technologies.** EPA's proposal arbitrarily sets the alternate technology minimum detection threshold to 10 kg/hr with a corresponding bimonthly survey frequency, coupled with an annual OGI survey. No supporting data are provided to demonstrate that this combination of technologies and frequencies is needed to achieve the desired emission reductions. Some operators are currently using alternate technologies with higher detection thresholds (e.g., 30 kg/hr), and the proposed framework should allow them the flexibility to continue the use of these technologies with an appropriate survey frequency. Conversely, the framework should also include lower detection thresholds and associated lower survey frequencies.

- **API supports the development of a matrix approach for alternate technologies.** For non-continuous technologies, the matrix should prescribe a minimum detection threshold based on a given survey frequency. The minimum detection threshold should be based on modeling (such as, but not limited to, FEAST or LDAR-Sim) that demonstrates that the alternate technology is expected to achieve the required emission reductions. This approach would not specify particular technologies or deployment platforms and would allow for easy use of future technologies so long as they meet the required minimum detection threshold. The proposed matrix could look like the following example.

Minimum Methane Detection Threshold (kg/hr)	Survey Frequency (x per year)
A	3
B	4
C	6

API members look forward to continued engagement with EPA on alternate leak detection technologies and in developing this matrix approach as EPA works towards the supplemental proposal. Our experience with modeling suggests monitoring frequency could be reduced to 4 surveys and one annual OGI inspection.

- **In the interest of transparency, any modeling results and information used to justify a proposed set of alternate technologies/detection thresholds and associated survey frequencies should be publicly available.** For others to evaluate and verify any proposals, it is necessary to have all relevant modeling information, including targeted control efficiencies, data inputs and assumptions. This transparency will be important both for any EPA modeling as well as modeling results submitted to EPA by other stakeholders.

- **The framework should support the use of multiple monitoring technologies for effective combinations of leak detection.** The framework should allow operators to implement one or more technologies to achieve the emission reduction goals. A combination of M21, OGI, and alternate technologies implemented at various frequencies can be as or more effective as a single technology at a given frequency. A matrix like the one above would allow operators to implement any technology that meets the minimum detection threshold for any given survey at the required frequency (i.e., a different technology could be used for each of the required surveys so long as it meets the minimum detection threshold). Separate matrices could also be developed based on a requirement to perform an annual OGI or M21 survey in addition to the screenings with alternate technologies. The frequency and detection threshold matrices would be supported by modeling.

- **The framework should also support the use of continuous monitoring technologies.** Continuous monitoring technologies can detect large leaks in real-time. API members see great promise in continuous/near-continuous methane monitoring technologies and encourage EPA to work with stakeholders to develop a framework that allows for usage of such technologies. Potential elements of the framework could include guidance on the content of an operator's continuous monitoring plan, including information such as types of sensors, modeling, placement of sensors, detection thresholds, downtime, networking/software, data fusion and management, follow-up procedures and QA/QC. To inform development of a proposed framework, EPA should consider hosting a multi-stakeholder workshop(s) prior to release of the formal regulatory text. API members look forward to working with EPA on pathways to developing monitoring programs.

- **A streamlined approval process should be included for future technologies that do not fit the existing framework.** API recognizes the challenges of writing regulations for a variety of alternate technologies and supports the inclusion of a streamlined approval process for alternate methane detection technologies that may not meet the prescribed framework but can be demonstrated to be as effective at reducing emissions. If such a technology is approved for one company, EPA should provide a pathway for other companies to implement this new technology under the same conditions approved, without the administrative burden of repeating an approval process that has already been reviewed and completed by EPA.

- **The proposed 14-day follow-up OGI survey should be focused on the highest emitting non-authorized sources and not be required for all emissions detected with alternate technologies.** The framework should limit follow-up OGI surveys to sites where the source of a persistent leak cannot be identified from the alternate technology screening data or other operational data. Not all emissions are actual persistent leaks. Where the alternate technology or operational data can identify the source of the detected emissions, the operator will evaluate whether the detected emissions represent an event that needs to be repaired or represent authorized emissions from the site. Where the source of an event can be identified by alternate technology or operational data, operators should have the option to not conduct a follow-up OGI survey and instead begin repair attempts. This option will focus operators' time and effort on repairing leaks instead of conducting follow-up OGI surveys to confirm information already provided by the alternate technology or other operational data.

  When required, follow-up OGI surveys should be prioritized for the sites with highest detected emissions; this approach will focus operators' time and effort on the repairs with the greatest environmental benefit. The framework should define clear thresholds for this prioritization of follow-up OGI surveys or repair attempts.

- **Timelines for a follow-up OGI survey or an initial repair attempt should be based on the date that final data (i.e., data that have undergone proper QA/QC procedures by the vendor) from the alternate technology screening are received.** Depending on the number of sites surveyed, final data from an alternate technology screening can be received days to weeks after the date that the actual survey is conducted. Compared to OGI surveys, alternate technology screenings allow operators to survey up to hundreds of sites more quickly and identify and repair large emission events. Although preliminary data from alternate technology screenings can be informative, the final processed data that has undergone proper QA/QC provides the operator more confidence in the results and contains more detail that allows the dataset to be actionable. The timeline to complete the follow-up survey or initial repair attempt should begin on the date that the final data report is received by the operator.

5.0 LEAK DETECTION AND REPAIR AT GAS PROCESSING PLANTS

API generally supports EPA's proposal for bimonthly OGI monitoring for equipment leaks at gas processing plants. We also support retention of NSPS VVa as an alternative monitoring option, as some facilities have compliance obligations through consent decrees or permits or are subject to state or local regulations that require the use of M21. In general, we also support the use of Appendix K for OGI monitoring at gas processing plants with appropriate changes as detailed further in Comment 3.0 and Attachments A and B.

We have additional suggestions to improve the described proposal and address implementation concerns as follows:

- **The proposed bi-monthly OGI monitoring requirements should also apply to closed vent systems and equipment designated with no detectable emissions.** This equipment should be treated like other fugitive emission components similar to the requirements option for quarterly M21 monitoring of pressure relief devices in NSPS OOOO and OOOOa (40 CFR 60.401a5401(b)). The increased frequency of bi-monthly OGI monitoring compared to an annual M21 survey should allow OGI to be as effective as M21 at detecting leaks from this equipment. Bi-monthly OGI monitoring would also decrease costs since a separate M21 program would not be required.

- **EPA should not remove the VOC concentration threshold from the proposed LDAR requirements and should instead propose a similar concentration threshold for methane.** EPA should retain the current 10.0 percent by weight threshold for VOC and add a 1.0 percent by weight threshold for methane. While EPA is correct that a VOC concentration threshold is not an appropriate threshold for determining whether LDAR for methane applies, EPA failed to realize that some streams at a gas processing plant have de minimis concentrations of VOC and methane (e.g., purity ethane, produced water, wastewater). Without appropriate concentration thresholds, equipment with no appreciable amounts of VOC or methane would be subject to LDAR requirements, which API does not believe was EPA's intent with this proposal. Minimum concentration thresholds are especially important if an owner or operator chooses to use M21 since tagging of components are required (along with accounting for and maintaining these tags); monitoring additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with little environmental benefit.

6.0 STORAGE VESSELS

6.1 For completely new surface sites, API supports the proposed 6 tpy VOC threshold for a single storage vessel or tank battery.

API supports EPA's proposed 6 tpy VOC threshold for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. Although not discussed in the proposed rulemaking for NSPS OOOOb, API encourages EPA to retain the current alternate control standard in NSPS OOOOa to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC. In the preamble to the NSPS OOOO revisions dated April 12, 2013[25], EPA noted that removal of control at 4 tpy VOC will reduce emissions from burning more pilot gas than the waste gas being burned. Below are additional considerations regarding control requirements for a single storage vessel or tank battery:

- **As oil production declines, operators may need to replace the original storage vessel or tank battery combustion device with a smaller capacity device.** Applying the same threshold as a single storage vessel to a tank battery means that a control device will be required for a longer duration. This longer control duration and potential additional costs for a smaller replacement control device were not considered in EPA's cost analysis.

- **EPA should allow for an exemption from control requirements due to technical infeasibility if the control device would require supplemental fuel**. This type of exemption has been rationalized by state regulations for storage vessels and tank batteries, such as in Colorado, where there is an exemption from control requirements for tanks if use of a control device would be technically infeasible without supplemental fuel for pilot or other purposes. API recommends that EPA consider such an exemption for NSPS OOOOb and EG OOOOc. The regulatory text for the Colorado exemption is provided for consideration below.

> *Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.*

6.2 The proposed definition of tank battery should be based on manifolded tanks by liquid line.

EPA's proposed definition of a tank battery is overly complex given the objective of including a tank battery as a storage vessel affected facility. Based on the definition of a "storage tank" in Colorado

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[25] Federal Register Vol. 78, No. 71, 22133-22134

Regulation 7, "manifolded by liquid line" is a simple and clear criterion for defining a group of storage vessels as a tank battery. The Colorado Air Quality Control Commission established a definition for a "storage tank" for Regulation 7 by expanding upon the definition of a storage vessel in NSPS OOOO and OOOOa to include storage vessels manifolded together by liquid line. The other criteria (e.g., physically adjacent, manifolded for vapor transfer) in EPA's proposed definition would cause potential confusion around applicability. We offer a suggested definition of a tank battery based on EPA's proposal language (86 FR 63178) as follows:

> *The EPA proposes to define a tank battery as a group of storage vessels that ~~are physically adjacent and that receive fluids from the same source (e.g., well, process unit, compressor station, or set of wells, process units, or compressor stations) or which~~ are manifolded together for liquid ~~or vapor~~ transfer.*

6.3 The proposed definition for a modification of a tank battery requires additional clarification.

The EPA is proposing to require that the owner or operator recalculate the potential VOC emissions when certain actions occur on an existing tank battery to determine if a modification has occurred. EPA's proposed definition for a modification of a storage vessel or tank battery is inconsistent with NSPS Subpart A and requires additional clarification. Per 40 CFR 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification.

EPA should also clarify whether other individual storage vessels in an existing tank battery remain affected facilities under NSPS OOOO or NSPS OOOOa, as applicable, or become part of the modified tank battery under NSPS OOOOb.

API recommends the following changes:

> "The EPA is proposing that a single storage vessel or tank battery is modified *when physical or operational changes are made to the single storage vessel or tank battery that result in an increase in the potential methane or VOC emissions. Physical or operational changes ~~would be defined~~ include:*
>
> *(1) The addition of a storage vessel, to an existing tank battery;* or
>
> *(2) replacement of a storage vessel, such that the cumulative storage capacity of the existing tank battery increases.~~; and/or~~*
>
> *~~(3) an existing tank battery or single storage vessel that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery)."~~*

6.4 API generally supports EPA's proposal for existing storage tank batteries under EG OOOOc.

API generally supports EPA's proposal for 95 percent emission reduction for existing storage vessels and tank batteries with potential methane emissions of 20 tpy or more under EG OOOOc. That said,

- EPA should provide an exemption from control requirements due to technical infeasibility if the control device would require supplemental fuel.

- One additional consideration for existing storage vessels or tank batteries is the additional cost for control at sites in dry gas plays with produced water storage vessels or tank batteries only. Some of the produced water storage vessels are fiberglass tanks and would have to be replaced with steel tanks to support the installation of a closed vent system and control device due to backpressure. The additional cost for storage vessel replacement was not included in EPA's cost analysis. If capital costs to replace a storage vessels(s) are $20,000 or more this would result in a cost effectiveness of over $1,900 per ton of methane reduced for a combustion control device using EPA's own cost analysis.

6.5 API supports EPA's proposed alternative approach to specify within NSPS OOOOb and OOOOc that storage vessels at well sites and centralized production facilities are subject to requirements in those regulations instead of NSPS K, Ka, or Kb.

As EPA states in its proposal (86 FR 63184), "this alternative approach would eliminate the need for sources to determine if the storage vessel meets the exemption criteria specified in those subparts and instead focus on appropriate controls for the storage vessels based on the location and type of emissions likely present (e.g., flash emissions)." API believes that this approach provides a clearer path for determining regulatory applicability for storage vessels in the production segment. API notes that some storage vessels at production facilities store liquids that do not contain dissolved gases. For those tanks, facilities could still opt to control emissions using a floating roof, as is currently allowed under NSPS OOOOa (40 CFR 60.5395a(b)).

7.0 WELL LIQUIDS UNLOADING OPERATIONS

7.1 API generally supports a work practice standard built around the Best Management Practices approach described by EPA in this proposal.

API generally supports a work practice standard built around the Best Management Practices (BMP) approach described by EPA in this proposal. We support EPA in allowing flexibility for operators to manage and operate their wells based on the engineering needs of the well. As a point of clarification, we note that EPA's discussion of liquids unloading methods in the Technical Support Document to this proposal characterizes several techniques as non-venting techniques. Some of the solutions discussed may minimize emissions from unloading, but not fully eliminate them.

- **Contingent on clarification that these requirements are specific to liquids unloading of gas wells that vent emissions to atmosphere, we support EPA's proposed Option 2.** EPA should confirm that the liquids unloading requirements will apply to gas wells that vent emissions from liquids unloading to atmosphere only. Since EPA's process description in the Technical Support Document for liquids unloading mentions only gas wells, we believe that it was EPA's intent to limit the affected facility for liquids unloading to gas wells only.

- **EPA's proposal for Option 1 is not feasible**. As proposed, Option 1 would require operators to track all unloading events. This would include unloading events that are automated on artificial lift or pump jacks and even those that do not vent any emissions to the atmosphere. We do not support this approach as there is no environmental benefit associated with this Option and it would generate a significant amount of administrative burden.

- **Operators already report the number of liquids unloading events to EPA under the Greenhouse Gas Reporting Program.** In the proposal, EPA has described the reporting information for wells that utilize methods that vent to the atmosphere as including the number of liquids unloading events in an annual report, which is duplicative of other EPA reporting requirements.

- **EPA is correct in allowing flexibility for liquids unloading operations.** Well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective. There are numerous misconceptions about why and how this activity is conducted. The technology options EPA describes in the proposal are designed to remove liquids from a well. Their function is not to reduce emissions resulting from gas that might be entrained in the liquids removed. For some situations a certain technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. Therefore, we support EPA in providing criteria for consideration for inclusion in an operator's BMP, as listed in the proposal and provided below, but not dictating all specific practices:

> *"BMPs would require operators to monitor manual liquids unloading events onsite and to follow procedures that minimize the need to vent emissions during an event. Such as:*
>
> - *having a person on-site during the liquids unloading event to expeditiously end the venting when the liquids have been removed,*
> - *following specific steps that create a differential pressure to minimize the need to vent a well to unload liquids and reducing wellbore pressure as much as possible prior to opening to atmosphere via storage tank,*
> - *unloading through the separator where feasible, and/or*
> - *closing all well head vents to the atmosphere and return of the well to production as soon as practicable."*

- **EPA must clearly define liquids unloading within NSPS OOOOb.** Other well maintenance and workover activities may occur on a well. These activities are distinctly different, require different equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. To address this clarification, we offer the following definition for "Liquids Unloading":

> *"Liquids Unloading" means the removal of accumulated liquids from the wellbore that reduce or stop natural gas production from natural gas wells. Routine well maintenance activities, including workovers, swabbing, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.*

8.0 ASSOCIATED GAS VENTING FROM OIL WELLS

8.1 API supports elimination of venting from "each oil well that produces associated gas and does not route the gas to a sales line" with additional clarifications.

While EPA's proposal is overly broad in its description, API generally supports and recognizes the environmental benefit of the elimination of venting of associated gas from oil wells that do not currently route gas to a sales line (EPA's proposed option 2). If associated gas cannot feasibly and economically be recovered to a sales line, API supports capturing the gas for a beneficial use or flaring the gas such that 95% control efficiency is achieved.

8.1.1 Special considerations for handling associated gas at wildcat and delineation wells.

EPA did not allow provisions for wildcat or delineation wells in its proposal. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. Like provisions within NSPS OOOOa for well completions, EPA should allow special considerations for handling associated gas at these types of operations. Specifically, any associated gas initially generated from wildcat or delineation wells should be routed to a combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways).

8.1.2 EPA correctly identified that access to a sales line does not equate to availability of a sales line.

API agrees that EPA correctly characterized scenarios *"when gas capture may not be feasible, such as when there is no gas gathering pipeline to tie into, the gas gathering pipeline may be at capacity, or a compressor station or gas processing plant downstream may be off-line, thus closing in the gas gathering pipeline."* (86 FR 63237).

To further elaborate, access to a sales pipeline is based on numerous criteria that can be out of the control of the well operator. A few challenges (including those above) have been summarized below for EPA's awareness and consideration:

- **Topography:** Mountains, rivers, lakes, etc. can limit a producer's ability to connect into a pipeline.

- **A contractual right to flow into the gas gathering system must be agreed to with the company that owns the gathering line**. In most cases, the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added and if the quality of gas meets their required specifications.[26]

- **Necessary permits and ROW must be obtained for the pipeline from the well site to the natural gas gathering system.** Permits and ROW are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary ROW can be difficult and may require a court order. On certain federal lands, operators have been required by BLM in recent years to reroute proposed pipelines or to adjust installation techniques, which significantly delays the completion of gathering systems. On private lands, individual landowners may deny rights.

- **The natural gas must meet the specifications of the natural gas gathering line.** Contracts with the gathering company include specifications for entering the gas gathering line, such as allowable concentrations of inert gases such as carbon dioxide or nitrogen, and hydrogen sulfide. The natural gas gathering system owner ultimately controls when an operator can send gas to sales.

- **The natural gas gathering line must be operational.** Natural gas gathering lines can be temporarily down or unavailable for a multitude of reasons including, but not limited to, compressor maintenance or repair, line maintenance, line inspection, a gas plant being shut down, or temporary reductions in capacity. In some instances, a well will be connected to sales, but if a compressor station has an emergency upset, then the wells tied into the gathering system will not be able to send gas through the pipeline. These instances are often episodic, temporary, and not in the well operator's control.

Due to the various challenges described, EPA is correct in allowing the beneficial reuse of gas onsite or combusting the gas where accessing the pipeline is not available or technically feasible.

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[26] Additionally, capacity issues could exist even in cases where the production company is also responsible for the gathering system.

8.2 EPA underestimated the cost of installing a flare in its cost benefit analysis, using a value significantly lower than EPA estimates for flares for other affected sources.

EPA must re-evaluate the cost effectiveness using more relevant cost information that is consistent with how flares are costed for other emission sources. Throughout the Technical Support Document for this proposed rule, EPA has assumed various costs with respect to installing a flare or other combustion device.

In review of EPA's cost evaluation data for associated gas from oil wells, EPA assumed that a flare would cost only $5,700. This value significantly underrepresents actual costs experienced by operators. A more representative cost for installing a flare suitable to control associated gas would be $100,579, based on the average costs EPA uses for analyzing storage vessel controls. To obtain an average cost of $100,579 per flare, we reviewed the direct capital costs associated with calculation sheets issued by EPA[27] as listed in the following table:

EPA Flares Calc Sheet MP1 **Small Flare**	**EPA Flares Calc Sheet MP2** **Medium Flare**	**EPA Flares Calc Sheet MP-G** **Large Flare**	**EPA Flares Calc Sheet MP-H** **Largest Flare**	**EPA Estimated Average Costs for Various Sized Flares**
$79,352	$84,761	$92,874	$145,328	**$100,579**

Note that we did not include the costs from EPA's Workbook *'MP1 Plus Monitors.xlsx'* as this would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the proposal. If EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA's cost analysis.

9.0 OTHER PROPOSED STANDARDS

9.1 Pneumatic Pumps

We generally support the pneumatic pump provisions as described in the proposal for NSPS OOOOb and EG OOOOc.

As noted in our December 4, 2015[28], comments on the proposed Subpart OOOOa[29], there are numerous implications for routing a piston pump to a control device or VRU and we continue to support EPA in excluding piston pumps from EG OOOOc.

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[27] https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0039

[28] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776)

[29] https://www.regulations.gov/comment/EPA-HQ-OAR-2010-0505-6884

9.2 Reciprocating Compressors

9.2.1 The applicability of the compressor standards requires clarification.

EPA should clarify the applicability of compressor standards to well sites, as the proposal is unclear. The definition proposed for central production facility may extend applicability to compressors located at well sites, which have historically been exempt from the compressor standards. As EPA states they have not updated their cost analyses with new information with respect to well sites, we believe extending applicability to well sites is not EPA's intent.

EPA should also provide clarification that temporary compressors (i.e., those onsite for less than 12 months) are not subject to these provisions. Additionally, EPA should consider whether it is appropriate to establish applicability thresholds based on compressor size, stages, or gas throughput or exclude compressors used in specific applications (e.g., casing, injection, gas lift compressors).

9.2.2 EPA should provide additional flexibility for addressing rod packing leaks.

EPA should provide flexibility by allowing operators the option to change out rod packing based on hours of operation/fixed frequency, like the current requirements in NSPS OOOO and OOOOa, or to perform the newly proposed annual monitoring and replacement of rod packing if a leak is identified.

Another potential option to streamline the monitoring burden is to allow operators to screen for leaks during annual OGI assessments and only perform measurement of the rod packing if it is identified as leaking during the OGI screening. This option has been approved under the Greenhouse Gas Reporting Program for gas processing and transmission facilities under 40 CFR Part 98, subpart W.

9.2.3 Proposed packing leak threshold and logistical monitoring concerns.

EPA should re-evaluate the designated leak threshold of >2 scfm per cylinder, as it may not be appropriate for all applications. Appropriate leak thresholds vary based upon the individual compressor type, size, and operating conditions. Our preliminary review indicates the 2 scfm/cylinder threshold proposed by EPA is an extension of regulations finalized in California[30]. In review of supporting documentation provided by the California Air Resources Board, it seems this threshold for rod packing replacement is based on data from a single vendor's alarm set point.[31] Publicly available data from another compressor manufacturer[32,33] indicates "expected packing leakage for typical alarm points is between 1.7 and 3.4 scfm", and experience from some API members indicates some maintenance may

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[30] https://ww2.arb.ca.gov/resources/documents/oil-and-gas-regulation

[31] See pages 109 -110 of the Initial Restatement of Reasoning, May 31, 2016. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf

[32] https://www.arielcorp.com/company/newsroom/compressor-emissions-reduction-technology.html

[33] https://www.arielcorp.com/application_manual/Arieldb.htm#Packing_Leakage.htm?Highlight=packing%20leakage

be conducted up to a 4 scfm threshold per manufacturer recommendations. Therefore, a more comprehensive review of compressor manufacturer information is required for determining an appropriate threshold for rod packing replacement under NSPS OOOOb and EG OOOOc.

Clarification is also needed on how the annual monitoring standard is applied for certain packing vent configurations and systems. For example, if an operator uses a continuous meter on a rod packing vent, how would compliance be demonstrated against the annual measurement? How will replacing the packing due to a different reason/program affect the annual monitoring window? When packing vents are manifolded together, is the standard determined by multiplying the leak threshold by the number of cylinders?

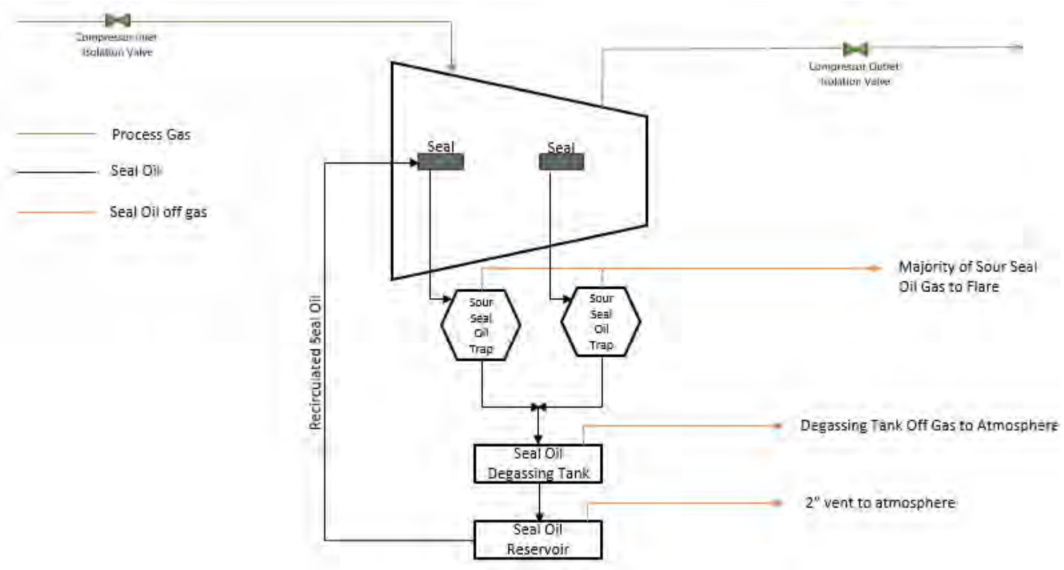
There are also practical considerations for how and when to conduct measurements. These types of concerns for implementation are well documented within subpart W for natural gas plants and transmission compressor stations. For example, the requirements in 40 CFR Part 98, Subpart W, only require rod packing measurements when a compressor is in operating mode at the time the measurement is set to occur (i.e., when the measurement team arrives onsite). Additionally, equipment modifications may be required to facilitate measurement of rod packing vents (e.g., adding an accessible port in vent piping), and adequate implementation time must be provided.

9.3 Wet Seal Centrifugal Compressors

9.3.1 Considerations for Compressors on the Alaskan North Slope

On the Alaska North Slope (ANS) there is not a market for natural gas sales. The majority of gas that is produced with the oil is separated and then compressed (using large wet seal compressors) to be reinjected back down hole for conservation and enhanced oil recovery. The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.

Wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures the vast majority of the gas by volume then routes that gas to a flare. The ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum/tank, where any remaining entrained gas breaks out and is vented to atmosphere. The following figure depicts this process:



In 2010, EPA's Natural Gas Star program[34,35], in conjunction with BP, conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis concluded that the sour seal oil degassing design employed on the ANS has greater than 99% emission control. That level of emission control is equivalent to a dry gas seal system.

Since dry gas seal systems are not subject to these proposed rules (due to their low leak rate), and the ANS wet seal degassing system design has demonstrated equivalence to dry gas seal systems, wet seal degassing designs employing sour seal oil traps should also not be subject to the rule. The two systems are equivalent from a venting perspective and should receive similar treatment under the regulations.

10.0 OTHER COMMENTS

10.1 Orphan and Unplugged Wells

The information below is provided to address EPA's queries concerning idle/abandoned and orphaned wells.

10.1.1 EPA does not have authority under CAA § 111 to impose financial assurance requirements.

EPA explains that it "is soliciting comment for potential NSPS and EG to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged

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[34] https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf

[35] https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf

ineffectively." 86 Fed. Reg. at 63240. Among other measures, EPA suggests that it "could require owners or operators to submit a closure plan describing when and how the well would be closed and to demonstrate whether the owner or operator has the financial capacity to continue to demonstrate compliance with the rules until the well is closed and to carry out any required closure procedures per the rule." *Id.* at 63241.

For the reasons discussed below, API believes that emissions from abandoned wells are not as great as EPA suggests and that issues related to well closure are more appropriately addressed by the states and BLM. Should EPA decide to further address this issue in the upcoming supplemental proposal however, the possibility of requiring a demonstration of financial capacity should not be a part of that proposed rule given EPA has no authority under the Clean Air Act to impose a financial assurance requirement.

EPA and states have authority under the CAA to establish "standards of performance" applicable to affected facilities. *See* CAA §§ 111(b)(1)(B) and (d)(1). The term "standard of performance" is defined in CAA § 111(a)(1) to mean, in relevant part, "a standard for emissions of air pollutants" – *i.e.*, an emissions limitation or comparable requirement (such as an equipment or work practice standard). This is reinforced by the more broadly applicable CAA § 302(l) definition of "standard of performance," which defines that term to mean "a requirement of continuous emissions reduction." Neither of these definitions can reasonably be construed as authorizing EPA to issue financial assurance requirements for affected facilities.

In conjunction with the obligation of EPA and states to issue standards of performance, the Clean Air Act provides authority to establish corresponding compliance assurance measures, such as monitoring, recordkeeping, and reporting requirements. CAA § 114(a). However, a financial assurance requirement is fundamentally different in kind from such measures. Monitoring, recordkeeping, and reporting are designed to provide information necessary to determine applicability and demonstrate compliance with a standard of performance. In contrast, a financial assurance requirement is designed to make sure enough money is available to implement a standard of performance at some point in the future. Nowhere in the CAA is there express or implied authority for EPA to establish such a requirement.

Notably, in instances where Congress wants EPA to require financial assurance, authorization has been explicit. *See, e.g.,* 42 U.S.C. § 6924(a)(6) (Requiring EPA to establish rules for treatment, storage, and disposal facilities regulated under the Resource Conservation and Recovery Act to ensure "the maintenance of operation of such facilities and requiring such additional qualifications as to ownership, continuity of operation, training for personnel, and financial responsibility (including financial responsibility for corrective action) as may be necessary or desirable."). The absence of such an express provision in the Clean Air Act cannot be construed as a grant of authority.

10.1.2 Substantial progress on – and additional information concerning - idle/orphaned well clean up may be expected based on recent federal funding.

Passed as part of the Infrastructure and Investment Jobs Act of 2021, the REGROW Act provides funding to invest in the environment, and a skilled workforce. This includes $4.275 billion for orphaned well clean up on states and private lands, $400 million for orphaned well cleanup on public and tribal lands, and $32 million for related research, development, and implementation.[36] Any applications from states for these grant funds can help provide more concrete numbers. Additionally, any of these funds that are distributed as grants to state agencies may contain additional environmental and reporting obligations, which, when viewed in the proper context, may lend additional light to this issue. These recent developments further minimize the need or justification for EPA to expand its regulatory efforts on this topic to encompass orphan wells.

10.1.3 Further granularity on idle/orphaned wells was provided in December 2021, when the Intergovernmental Oil and Gas Compact Commission (IOGCC) released an update of its 2019 report on idle and orphaned wells to include 2019 – 2020 data. Because IOGCC's work is based on over 30 years of review, EPA should consider this information carefully before determining a course of action.

The Interstate Oil and Gas Compact Commission (IOGCC) is a multi-state government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. As an organization, IOGCC is committed to continuing to support the states and provinces in their efforts to continually improve their idle and orphan well programs and also to providing a forum for information-sharing of effective tools and strategies. IOGCC has also been included in the DOI MOU[37] for the recently enacted grant program referenced above.

Across decades of studying idle and orphaned wells, the IOGCC has published reports on the issue in 1992, 1996, 2000, 2008, and 2019.[38] A new report covering data from 2019 and 2020 was published in December 2021.[39] As these reports show, the IOGCC has been following this issue for 30 years. API encourages EPA and other agencies interested in regulations on this topic to review the report in detail.

The 2021 IOGCC report features survey responses from 32 IOGCC member and associate member states and five Canadian providences. It includes data from 2018 – 2020 and concerns the number of both idle and orphan wells, well plugging and site restoration costs, and remediation strategies (including regulatory tools and funding sources used to ensure idle wells are properly maintained).

The IOGCC report also provides helpful clarification of terminology, which is often misused in idle/orphan well conversations. We encourage EPA to align its terminology with the terminology used by IOGCC to reduce confusion:

- ***Idle Wells.*** The IOGCC defines idle wells as "wells that have not been plugged and are not producing, injecting, or otherwise being used for their intended purposes."[40] Similarly, they note that "[M]any idle wells have potential for oil or gas production or associated uses."[41] The future

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[36] REGROW Act Infrastructure and Investment Jobs Act of 2021, H.R. 3684, 117th Congress (2021).

[37] Orphan Well MOU (doi.gov)

[38] Interstate Oil and Gas Compact Commission (IOGCC), Idle and Orphan Oil and Gas Wells, (2019).

[39] Interstate Oil and Gas Compact Commission (IOGCC) Idle and Orphan Oil and Gas Wells, (2021).

[40] IOGCC *(*2021) at 2.

[41] *Id.*

outcome for an idled well could be that it is brought into production, plugged, or converted to an injection well for enhanced oil recovery or for disposal. Most regulatory agencies set a timeline and requirements (whether statutory, by rule, or by specific written approval) for how long a well may remain idled before it must be plugged. The total number of approved idle wells reported by the states as of December 31, 2020, is 231,287, which is 14 percent of the total number of documented wells that have been drilled but not plugged.[42] Notably, despite including 4 more states in the 2021 report, this is down over 20 percent from the IOGCC's 2019 figures, which featured "a total number of approved idle wells is 294,743, which is 15.6 percent of the total number of documented wells that have been drilled and not plugged."[43] In the three years covered by this report, operators plugged 62,463 wells in the states[44].

- ***Orphan Wells.*** The IOGCC defines orphan wells as "idle wells for which the operator is unknown or insolvent. Most states and provinces have inventories of documented orphan wells and prioritize orphan wells for plugging according to risk. As of December 31, 2020, the states reported a total of 92,198 documented orphan wells, and the provinces reported a total of 5,015 documented orphan wells. In the states, the number of documented orphan wells increased by 50 percent from 2018 to 2020, due primarily to the efforts of states to document these wells through investigation and verification of the status of wells and their operators. In the three-year period from 2018 through 2020, the states plugged 9,774 orphan wells and the provinces plugged 4,930. In total through 2020, the states have plugged over 78,000 orphan wells and the provinces almost 6,300."[45]

- ***Undocumented Wells.*** The IOGCC identified undocumented wells as a category for further work, noting that these are mostly a historical concern. Unverified estimates "do not convey a reliable picture of the actual number or the potential associated risk. The estimates are by their nature imprecise, and many undocumented wells may not constitute a significant risk to the environment or public health and safety."[46] It is important to understand that the lack of plugging documentation for these wells does not mean they were never plugged and the lack of the locations for such wells make any action or quantifications difficult. Thanks to modern record-keeping and regulation it is uncommon to be unable to identify the owner or operator a well. The majority of orphaned or undocumented wells occur as a result of development before the 1950s. For example, Pennsylvania is estimated to have the largest number of orphaned wells in the country, and the Pennsylvania Department of Environmental Protection explains, "Since the first commercial oil well was drilled in Pennsylvania in 1859, it is estimated that 300,000 oil and gas wells have been drilled in the state. Only since 1956 has Pennsylvania been permitting

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[42] *Id.*

[43] IOGCC *(*2019)at 5.

[44] IOGCC (2021) at 2.

[45] *Id.*

[46] Id at 3.

> new drilling operations, and not until 1985 were oil and gas operators required to register old wells."[47]

10.1.4 EPA should not create duplicative and unnecessary regulations, which may conflict with specific rules promulgated by the states and BLM to address orphaned, idle, and abandoned wells.

Oversight for idle, orphan, and historical undocumented orphan wells is state-specific according to local regulatory programs, most of which include requirements for wells to remain idle and established prioritization systems for known orphaned wells. Additionally, most states already have funding mechanisms for plugging orphan wells, which are supported by industry taxes and fees. To avoid duplication or unintended consequences, the EPA should carefully examine these diverse programs and funding mechanisms prior to any additional regulatory work.

As an example of continuous improvement within the applicable states, over half of the states and provinces participating in the IOGCC survey reported improvements in their idle and orphan well programs between the IOGCC reports in 2008 and 2021. In 2019, the IOGCC noted that these included "process improvements in communication, collaboration, contracting, third-party plugging, compliance assurance, data systems, and bonding; implementation of program efficiencies; increases in staffing and funding; and application of Geographic Information System (GIS) and drone technologies. Through the decades, the states and provinces have made considerable progress in plugging orphan wells and reducing the likelihood of additional wells becoming orphaned. They have also continued to evaluate and adjust their financial assurance requirements and their plugging funds to ensure there will be funds available for well plugging and site restoration."[48]

The 2021 IOGCC report expanded its description of regulatory strategies used by the various states which include, "requirements, such as periodic mechanical integrity testing, that must be met for wells to remain idle beyond a specified time. These requirements may be set by statute, rule, or written approval. Most states and provinces also require financial assurance to provide money for plugging and restoration if the operator defaults. Financial assurance instruments include cash deposits, certificates of deposit, financial statements, irrevocable letters of credit, security interests, and surety or performance bonds. The types accepted and amounts required vary considerably among the states and provinces. The participating states all provide for single-well and blanket coverage, and the participating provinces provide for either single-well or blanket coverage, or both. The amounts may be uniform for all wells, or they may be based on the depth, location, type, or status of well or case-by-case evaluations. To supplement the funds provided through financial assurance instruments, most states and provinces have established funds dedicated to plugging orphan wells. Money for these funds comes primarily from taxes, fees, or other assessments on the oil and gas industry. Nineteen states and provinces reported on innovations and advancements in their idle and orphan well programs. Some

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[47] DEP Quote Pennsylvania Department of Environmental Protection, "The Well Plugging Program", available online at https://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/AbandonedOrphanWells/WellPluggingProgram.pdf

[48] IOGCC (2019) at 21.

have added staff, improved their data management systems, and streamlined their contract management processes. Some have adopted new idle well requirements, such as requirements to provide additional financial assurance, demonstrate well integrity, justify keeping wells in idle status, or limit the percentage of wells an operator may hold in idle status. Increasingly, states and provinces are using Geographic Information Systems (GIS) and drone technologies to find orphan wells. They are also collaborating with operators and landowners to address idle and orphan wells and using grant programs, economic stimulus funds, and third-party partnerships for orphan well plugging and restoration."[49]

Activities on federal lands are regulated both by BLM regulations and by the state in which the operations are located. On federal lands, however, existing federal regulations obligate companies to bear the full costs of plugging and abandoning well sites.[50] In fact, companies cannot be released from liability until BLM determines they have properly done so. The April 2019 GAO report identified 296 orphaned wells which is a very small and manageable percentage of the 96,199 onshore federal wells.[51]

Beyond state and federal requirements, the oil and gas industry has developed relevant standards and practices which apply on both state and federal lands. These are relevant throughout a well's lifecycle; covering the safe conduct of drilling operations, standards for equipment and materials used during drilling and completion, and practices for well plugging and abandonment. In 2021, API's Recommended Practice (RP63),5- *Wellbore Plugging and Abandonment* provided specific guidance for the design, placement and verification of cement plugs used in wells that will be temporarily or permanently closed.[52] The standard also provides guidance for well remediation and verification of annular barriers, reinforcing groundwater protection and emissions retention. RP 65-3 joins several established API standards already in use for decades, including but not limited to API 51R, *Environmental Protection for Onshore Oil and Gas Production Operations and Leases* and API 65-2**,** *Isolating Potential Flow Zones During Well Construction***.** These are instructive templates for better understanding how industry practices work effectively across varying state and federal regulations.

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[49] IOGCC (2021) at 3.

[50] Ref federal regs See e.g., Bureau of Land Management, Onshore Order No. 2, 53 Fed. Reg. 223 (1988), available at https://www.blm.gov/sites/blm.gov/files/energy_onshoreorder2.pdf , and other onshore orders available at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/onshore-orders

[51] Government Accountability Office, Report 19-615 Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Repair Wells (2019) p. 14, citing Footnote 30 explaining that anecdotally BLM also indicated some of these 296 wells may no longer be orphaned.

[52] API RP-63 American Petroleum Institute, Recommended Practice 65-3, *Wellbore Plugging and Abandonment* (2021).

10.1.5 The emissions from non-producing oil and gas wells are comparatively small and may currently be overestimated within the datasets used by EPA's Inventories Program on Climate Change.

It is noteworthy that, under EPA's current methodology, the emissions from non-producing oil and gas wells constitute approximately 3% of all methane emissions from the energy sector – a number similar to rice cultivation.[53]

Definitional challenges across state agencies and data sets can lead to apples-to-oranges comparisons. For example, the distinction between "abandoned" and "abandoned and plugged" is considerable. Beyond the IOGCC definitions discussed above, the oil and gas industry often refer to any well that has been properly plugged as "abandoned and plugged." Similar to industry, EPA's definition of "abandoned" includes all wells that are no longer in production; however, these wells may or may not be plugged, and may or may not be considered "orphan" as defined by IOGCC This type of information is part of an ongoing dialogue with EPA's Climate Change Division concerning potential updates to the U.S. Greenhouse Gas Inventory (GHGI).

In the attached letter (Attachment D) dated November 16, 2021, to Ms. Melissa Weitz, API recommended the following clarifications and revisions to EPA's proposed methodology,[54] all of which underscore the challenge of creating an accurate count of wells across data systems:

- **Correcting assumptions concerning plugged vs. unplugged wells.** API requests from EPA a better explanation of how it estimated the number of 1.1 million historical abandoned wells, which are not captured in the Enverus database. Moreover, API maintains that EPA should not assume that all historical (pre-Enverus) wells are unplugged, without further supporting information. Looking at the restructured Enverus data at the end of 1975, which is the date EPA used to develop its estimate of historical (pre-Enverus) wells, indicates that 72% of the wells that would be classed as 'abandoned' by the criteria in Table 3 of the 2022 memo are shown as actually 'plugged and abandoned'.[55] Hence, EPA should not ignore the Enverus data in favor of unsupported assumptions.

- **Using the IOGCC Data.** API contends that an alternative estimate of historically abandoned wells could be based on data for 'undocumented orphan wells' provided in the 2019 report issued by the Interstate Oil & Gas Compact Commission (IOGCC).[56] According to the IOGCC 2019

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[53] GHGI United States Environmental Protection Agency, Global Greenhouse Gas Inventory (2019).

[54] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-abandoned-wells_sept-2021.pdf 2 IOGCC, 2019, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies.

[55] API's analysis of Enverus data does not validate the information in Table 3 of the 2022 Abandoned Wells Update Memo as representative of calendar year 2019. However, the counts in Table 3 are broadly similar to API's analysis of current date Enverus well counts. API requests that EPA should validate that their modified query of the Enverus database for 2019 counts is correct and provide this information to stakeholders in an updated Table 3 if changes are substantive.

[56] See https://iogcc.ok.gov/sites/g/files/gmc836/f/documents/2021/2020_03_04_updated_idle_and_orphan_oil_and_gas_wells_repo rt.pdf Updates Under Consideration – 2022 GHGI

report the total estimated number of undocumented orphan wells reported by the states is between 210,000 and 746,000 (as shown in Table 1. Total Idle and Orphan Wells: All Surveyed States and Provinces (2018)). Beyond the IOGCC information, API is not aware of alternative, high quality sources of data readily available to inform the count of abandoned wells or the split into plugged and unplugged categories.

- **Avoiding the double counting of dry wells.** API also asks EPA to provide greater insight into the process of restructuring of the Enverus data set and the treatment of dry wells. API notes that the designation of "Dry Wells" in the Enverus database indicate a production type rather than a status type and EPA's approach of considering all wells with no cumulative production as abandoned wells is likely leading to double counting of dry wells in the abandoned well category since they are embedded in the well status counts. Furthermore, EPA's assumption that dry wells are unplugged is neither consistent with the Enverus data nor State plugging requirements. Current Enverus data shows that 93% of dry holes are plugged. Texas requires the same plugging standards for dry holes as for idle production wells and other State requirements are believed to be similar. Moving forward, API recommends that EPA should continue to use the Enverus production type field, where available, to classify wells into gas vs. oil and should also use the Enverus P&A status for determining what dry holes are unplugged. API further recommends that EPA should continue to use the cumulative production coupled with the well status and production type information to determine the count of dry wells.

In that same letter dated November 21, 2021, API also highlighted some data considerations which may lead to an overestimation of emissions from those wells:

- ***Considering the impact of state regulations.*** Many of the largest producing states have regulations in place spelling out emissions, discharge or integrity requirements that must be met when a well is non-producing. API stipulates that the simple assignment of the 'unplugged' designation to all the status codes that are not 'Excluded' or 'Plugged and Abandoned' (P&A) overlooks the potential impacts of such regulations and is therefore inaccurate. Such regulations, even if not directly promulgated to control volatile emissions, have the potential for lower emission rates from wells that are subject to regulation when inactive.

- ***Using geographically correct emissions factors.*** API commented previously on Abandoned Wells emissions when EPA introduced the update for the 2018 GHGI. API noted that the studies conducted so far have limited geographical coverage and may not be nationally representative. To clarify, EPA uses the "entire U.S." emission factors from the Townsend-Small study, which include the much higher Eastern U.S. (Appalachian - Ohio) emission factors. They then use these same Eastern US factors from Townsend-Small coupled with emissions from Kang 2016 to develop emission factors for Appalachian basin abandoned wells. API recommends that EPA should use the more appropriate "western U.S." emission factors for abandoned wells outside of the Appalachian basin.

- ***Treating outliers appropriately.*** Additionally, the Townsend-Small Appalachia data are dominated by one well with emissions of 146 grams/hour that is about an order of magnitude higher than any other well, plugged or unplugged, in the Townsend-Small data. API contends

> that it is not appropriate to include this well in the emission factor for the entire US. Also, to date no emissions data are available from the state of Texas or many other major producing areas, calling into question the representativeness of the extrapolation of the results of the current studies to a nationwide estimate of the contribution of CH4 emissions from Abandoned Wells to the GHGI.

Similarly, it is important to note that other parts of the U.S. government are already considering the question of outliers or super-emitters. During a recent presentation to the Health Effects Institute, Natalie Pekney from the Department of Energy's National Energy Technology Lab (NETL) presented research showing that a comparatively small number of super-emitter wells are increasing the average emission rate.[57] This estimate was based on NETL's techniques for locating undocumented orphan wells by searching for magnetic signatures (using walking, helicopters, and drones) which have been validated through field work in Pennsylvania, Oklahoma, and Kentucky. EPA may benefit from looking at NETL's work in more detail, particularly since NETL intends to undertake more work in this area in Kentucky, New York, and Texas over the next few years.[58] This observation would be consistent with the states' established practice of prioritizing plugging and abandonment for individual wells; consequently, EPA may benefit from learning more about both NETL's research and considering how it may already be applied at the individual state level.

10.2 Pipeline "Pigging" Operations

As mentioned by EPA, there are several alternatives for reducing the various emissions from pigging operations. As each location has a different set of circumstances for its operations, the focus should be on reducing emissions volumes associated with pigging operations, allowing facilities to implement the necessary emission reduction alternatives that are most appropriate.

Some alternatives might be appropriate for broad application and other alternatives could require unreasonable cost and infrastructure modification for minimal emissions reductions. Existing programs and practices already implemented by operators also need to be considered. There is a distinction in the feasibility of capturing and controlling pigging emissions from those pig launchers and receivers co-located at a compressor station or gas plant as compared to remote launcher and receiver locations where supporting infrastructure (i.e., electrical power, line jumpers to low pressure pipelines, flares, etc.) does not exist.

The discussion below provides an example of how emissions from a pig launcher or receiver can vary widely.

Emissions from a pig launcher or pig receiver occur primarily from opening the isolated pig barrel (and often a short distance of piping connected to the pig barrel) to either insert or remove a pig. The emissions are from the natural gas inside this isolated area when the pig barrel is opened, which is

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[57] Slide 8.Dr. Natalie Pekney, presentation on Health Effects Institute's webinar concerning "Abandoned and Orphaned Oil and Gas Wells," November 30, 2021.

[58] *Id.*

typically called a "blowdown." When a pig receiver is opened, there may be some residual liquids in the receiver, primarily from liquid falling off the pig itself. We note the volume of liquids in the receiver is unrelated to the amount of liquid a pig pushes down a pipeline. This limited amount of liquid in the receiver may have the potential for minimal flash emissions and perhaps volatilization.

Emissions from pig launchers and receivers vary widely based on several different, and sometimes interrelated factors: the diameter of the pig barrel and connecting midstream gathering pipeline; the length of the barrel or portion of the midstream gathering pipeline in between the pigging unit isolation valves; the pressure and composition of the gas within the unit; pig launching or receiving frequency; and the amount of liquids accumulation (applicable to receivers only). Consequently, frequency of pigging operations alone is not a good proxy for actual emissions as it is just one element that informs emissions. As a result, if one were to compare two pig launchers that are each used once per month, where the temperature is the same and the gas composition is the same, but the barrels have different diameters and lengths and different pressures, the actual emissions—calculated using the ideal gas law—from the two launchers would not be equal, potentially by a wide margin.

10.3 Tank Truck Loading Operations

Options typically used to reduce emissions from truck loading include routing emissions to a process (e.g., by installing a vapor recovery unit (VRU)) or to a combustion device. Many operators use a single, common VRU system or combustion device to control emissions from both hydrocarbon liquid transfers and storage tanks.

Practical, technical and safety issues that EPA should consider when evaluating potential truck loading emissions controls include the following:

- When loading emissions are to be routed to an existing combustion control device, substantial design evaluation work may be required to ensure that use of existing control devices is feasible, and if not, to design and install an additional or larger capacity combustion device.
- Some older facilities do not have the pad size to safely locate an additional combustor dedicated to loadout controls (if needed). Changes to the pad size require state agency and landowner approval, which may not be obtainable. Additionally, local governments and landowners may further prohibit operators expanding the footprint of a facility.
- If truck loadout vapors are routed through the storage tanks onsite prior to combustion, a new design analysis may be needed, which may generate costly modifications to low-producing sites (e.g., adding additional combustion control, larger combustors, change pipe sizing, etc.) in order to properly design the facility.
- Loadout truck drivers, who may not be familiar with truck loadout air emission equipment being used at these older low production facilities, will need additional training to safely use the new equipment. In many situations, the trucking company is a separate entity that may change over time from the producer.

- Older vintage buried and semi-buried tanks are not designed to work with truck loadout equipment.

- There are potential safety issues with the introduction of an oxygen rich vapor stream into atmospheric tanks that have minimal headspace. A higher oxygen percentage in the vapor mixture increases the risk of the vapor igniting and causing a fire or explosion. In these cases, the installation of an independent vapor control system may be required.

- Loading controls should not be required for sites where tanks are not required to be controlled.

- Lower producing facilities may have infrequent truck loadings based on production decline. EPA must evaluate the cost effectiveness of a reasonable threshold of crude oil/condensate prior to requiring any controls. Some states do not require loading controls if the number of loadouts is below a certain threshold or if the site routinely transfers liquids via a pipeline.

10.4 Opportunities to improve performance and minimize malfunctions on flares

EPA is soliciting comment on potentially proposing a change in the standards for wet seal centrifugal compressors, storage vessels, and pneumatic pumps that would require 98 percent reduction of methane and VOC emissions from these affected facilities. API does not support this change.

EPA also seeks comment on the appropriateness of applying standards from The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, amended in 2015 (80 FR 75178) to the oil and gas production, gathering and boosting, gas processing, or transmission and storage segments.

> *"The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, were amended in 2015 (80 FR 75178) to include a series of additional monitoring requirements that ensure flares achieve the required 98 percent control of organic compounds. Previously these flares had been subject to the flare requirements at 40 CFR 60.18 in the part 60 General Provisions. More recently, the updated flare requirements in NESHAP subpart CC have been applied to other source categories in the petrochemical industry, such as ethylene production facilities (40 CFR part 63, subpart YY), to ensure that flares in that source category also achieve the required 98 percent control of organic compounds. These monitoring requirements include continuous monitoring of waste gas flow, composition and/or net heating value of the vent gases being combusted in the flare, assist gas flow, and supplemental gas flow. The data from these monitored parameters are used to ensure the net heat value in the combustion zone is sufficient to achieve good combustion. The monitoring also includes prescriptive requirements for monitoring pilot flames, visible emissions, and maximum permitted velocity. Lastly, where fairly uniform, consistent waste gas compositions are sent to a flare, owners or operators can simplify the monitoring by taking grab samples in lieu of continuously monitoring waste gas composition, and in some instances, engineering calculations can be used to determine flow measurements."*

As we have provided feedback in the past[59], the refining sector is vastly different than oil and gas well sites, centralized production facilities, and compressor stations. The oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Oil and natural gas are located thousands of feet below the surface and must flow in two or three phases to the surface. The mixture is then separated in the two or three phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system.

As production declines in a gas well, management of wellbore liquids can mean that flow to the control device can vary from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible in these conditions.

Applying refinery-oriented requirements to upstream flares is not appropriate nor cost effective. Costs for Subpart CC controls at refineries are $1 million plus, with major ongoing costs. Costs would be much greater at upstream facilities without the necessary utilities and instrumentation resources. Nor is it clear that there is instrumentation available that would work reliably under the varying operating conditions. Additionally, adding natural gas to a flare to control the BTU content incurs capital costs as well as ongoing costs, and generates considerable greenhouse gases that would not otherwise be emitted.

We note that many states have moved to include some type of flare monitoring requirement within their local regulations or permitting processes. For example, Texas[60] requires that flares meet 40 CFR 60.18 requirements for minimum heating value and maximum tip velocity and have a continuous pilot flame (monitored by thermocouple or equivalent device) or an automatic ignition system.

10.5 EPA should clarify its statements regarding the Crude Oil and Natural Gas source category and the extent of crude oil operations for purposes of this rulemaking.

In footnote 2 of the proposal's Executive Summary section I.A. (86 FR 63113), EPA states:

> *"The EPA defines the Crude Oil and Natural Gas source category to mean (1) crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.* ***For purposes of this proposed rulemaking, for crude oil, the EPA's focus is on operations from the***

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[59] API's December 4, 2015, comments on the proposed Subpart OOOOa

[60] Texas Commission on Environmental Quality, *Control Device Requirements Charts for Oil and Gas Handling and Production Facilities* (February 2012). https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/control-dev-reqch.pdf

> ***well to the point of custody transfer at a petroleum refinery*** *[emphasis added], while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.*

Similarly, in the text in section III.B. (86 FR 63128), EPA states:

> *"The EPA regulates oil refineries as a separate source category; accordingly, as with the previous oil and gas NSPS rulemakings,* ***for purposes of this proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery*** *[emphasis added], while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate.''*

The implications of EPA's statements are unclear. We do not believe that EPA intends to regulate crude oil operations beyond the point of custody transfer from a well to a transmission pipeline (for example, operations at a crude oil pipeline breakout terminal). We request that EPA clarify these statements in the supplemental proposal.

10.6 Use of the Social Cost of Methane in the EPA Regulatory Impact Analysis

10.6.1 API recognizes the importance of including the potential impacts of climate change in regulatory impact analyses.

When performing a benefit-cost analysis as part of a RIA, EPA is justified in applying an estimate of the value of the impacts of a regulation to reduce greenhouse gases. This is especially true in a regulation which has as its primary purpose the reduction of greenhouse gases. As noted in OMB Circular A-4, the monetization of as many impacts as possible, and especially those central to the regulation, is essential to a properly conduced benefit-cost analysis.[61] However, specific care must be taken when using the social cost of methane estimates (SC-CH_4) as an input to the RIA. Per the recommendations of the National Academies of Science, Engineering and Medicine (NASEM) in their 2017 review of the social cost of carbon estimates (SCC),[62] the social cost estimates should be presented with a full discussion of the uncertainties associated with the development and presentation of those estimates. This RIA describes some of the uncertainties well and includes a presentation of the frequency distributions used to generate the social cost estimates. However, there are some issues that have not been addressed, including the inability to use a consistent set of socioeconomic and emissions scenarios to generate both

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[61] Office of Management and Budget, *Circular A-4* (September 17, 2003). https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf

[62] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. Washington, DC: The National Academies Press. https://doi.org/10.17226/24651

the social cost estimates and other benefits and costs associated with the regulation, and a consistent application of discount rates.

10.6.2 The interim social cost of methane estimates present a flawed approach to monetizing the impacts of climate change.

As noted in the 2021 Technical Supporting Document (2021 TSD), the interim social cost estimates represent the same methodological approach as the estimates generated prior to the disbanding of the Interagency Working Group (IWG) in 2017, and therefore rely on the same models and inputs from that effort.[63] API has previously commented on the social cost of greenhouse gas estimates (SC-GHG), including the SCC and the SC-CH_4 as developed by the IWG before 2017.[64] In these prior comment opportunities, API raised issues relating to the use of discounting, averaging across scenarios and Integrated Assessment Models (IAMs), the socio-economic and emission scenarios on which the modeling is built, and the handling of methane by the three IAMs on which the estimates rely. The conclusion upon reviewing these shortcomings of the previous and current interim SC-CH_4 estimates was "The SC-CH_4 (and SCC) estimates are highly uncertain and the causes of the uncertainty are not well understood."[65] While the NASEM study provided a better understanding of the uncertainties associated with the SCC and opportunities to improve the methodology of the SCC, the study did not extend to the SC-CH_4 nor did the IWG seek to improve the calculation of the SC-CH_4 in the publication of the interim values of 2021, as noted above.

10.6.3 Updates to the social cost estimates should be considered with robust stakeholder engagement.

The 2021 TSD notes that many of the same issues raised by API above are inputs that "need to be updated."[66] API and its members agree with this assessment; however, we have been concerned by the approach currently being taken by the IWG. As noted in API's comments to OMB regarding the Interim social cost estimates in June 2021, the actions taken thus far by the IWG do not reflect this administration's commitment to "public participation and an open exchange of ideas."[67] To date, there has been only one opportunity for stakeholder engagement in the social cost estimate development process initiated by E.O. 13990 – one that amounted to a request for information not an opportunity to comment on the work undertaken by the IWG. A recent brief filed by the Department of Justice suggests

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[63] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990* (February 2021), page 5. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[64] *See* multi-association comments filed February 26, 2014 (OMB-2013-0007-0140); API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776); and, API comments filed June 21, 2021 (OMB-2021-0006).

[65] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776).

[66] Interagency Working Group, 2021 TSD at 4.

[67] Executive Order 13563, *Improving Regulation and Regulatory Review* (January 28, 2011), at Sec. 1(a). https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/inforeg/inforeg/eo12866/eo13563_01182011.pdf

that stakeholders will have an opportunity to comment on the revised social cost estimates that the IWG will propose in spring of 2022. In its brief, the DOJ stated that the IWG will "publish its proposed final estimates within the next two months," and that the public will be given the opportunity to comment on these proposed estimates.[68] Further, EPA has published a request for nominations to form a panel to provide an independent, scientific peer-review of the forthcoming estimates.[69] The indication of both an independent, expert peer-review and a public notice and comment period is a welcome development. API encourages the IWG to use the forthcoming opportunities to engage with stakeholders, address comments that are provided and seek further feedback. Along these lines, we encourage EPA to submit for public comment a list of questions EPA is considering to guide the expert peer-review along with the list of candidates as outlined in the EPA request for nominations.[70] These forthcoming engagements represent an opportunity for the IWG and EPA to improve their process.

Separately, the DOJ brief also indicated that the IWG has not yet submitted recommendations for the use of the social cost estimates across federal decision-making. API encourages the IWG and the White House to publish those recommendations, in full, for public comment.

API and its members look forward to the opportunities noted above to engage with the IWG and relevant agencies on the development and application of the social cost estimates. The provision of a well-developed estimate of the impacts of greenhouse gas emissions is key to regulations that seek to address such emissions. Failure to engage with stakeholders directly during the process or during a public comment period specifically to address the methodology of the estimates may jeopardize the durability of regulations dependent on this analysis. API encourages EPA, as a member of the IWG, to direct the IWG to follow through on the administration's commitment to public participation by opening the process and engaging directly with stakeholders.

Given the timeline set by this administration, and the updated timeline for the proposal of revised social cost estimates, it is likely that the IWG will have proposed a revised set of social cost estimates for stakeholder review and comment prior to EPA issuing a supplemental proposal or a final rulemaking for methane emissions from the oil and natural gas sector. API encourages EPA to complete a revised RIA including these new estimates and other factors as necessary before moving forward.

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[68] Def. Supp. Br., 23, *La. v. Biden*, No. 2:21-cv-01074 (W.D. La. Jan. 21, 2022).

[69] On Tuesday, January 25th, EPA published a request for nominations of experts to act as reviewers of the proposed final estimates and the accompanying Technical Supporting Document (TSD). 87 Fed. Reg. 3801 (January 25, 2022)

[70] 87 Fed. Reg. 3803 (January 25, 2022)

11.0 OVERARCHING LEGAL ISSUES

11.1 The Proposal cannot set the new source trigger date under Subpart OOOOb because regulatory text is missing.

EPA proposes that the new source trigger date for Subpart OOOOb is November 15, 2021, the date the Proposal was published in the Federal Register. But here, publication of the Proposal cannot set the new source trigger date because the Proposal lacks proposed regulatory text, which is vital for fully assessing applicability and compliance. We appreciate EPA's promise to make proposed regulatory text available in an upcoming supplemental proposal. But that promise is not sufficient to set the new source trigger date at November 15, 2021.

Lack of proposed regulatory text creates an insurmountable practical problem. Affected facilities cannot know with certainty what regulatory requirements EPA has proposed and are thus unable to reasonably plan to comply with the final rule. Affected facilities can only surmise what the rule would require based on the description and explanation provided in the preamble. But affected facilities cannot know with sufficient clarity what would be required under the Proposal because they cannot see the part of the proposal that matters most – the regulatory text that would establish the binding legal obligations that would be imposed under the proposal.

As an initial matter, the lack of regulatory text means that the Proposal does not give fair notice to potentially affected facilities of what requirements they might be required to meet upon the effective date of the final rule. Fair notice is only achieved when EPA provides regulated entities with sufficient detail of what exactly will be required, which it has not done here.

Moreover, the publication date of the Proposal does not set the trigger date because it is not a proposed "regulation." CAA § 111(a)(2) defines "new source" to mean "any stationary source, the construction or modification of which is commenced after the publication of regulations (***or, if earlier, proposed regulations***) prescribing a standard of performance under this section which will be applicable to such source." CAA § 111(a)(2) (emphasis added). Thus, only a proposed "regulation" may set the new source trigger date.

The term "regulation" is not defined in the Clean Air Act. However, the term "regulation" is synonymous with the term "rule," which is defined in the Administrative Procedure Act to mean (in relevant part) "the whole or a part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or describing the organization, procedure, or practice requirements of an agency." 5 U.S.C. § 551(4).

Here, the preamble alone cannot constitute a proposed rule any more than a final rule that is unaccompanied by regulatory text could be declared a "rule." Although the current preamble describes the type of regulatory requirements that EPA proposes to eventually promulgate, the preamble is not in and of itself a document that establishes the "agency statement of general or particular applicability and future effect." That type of required statement would be established only by the proposed regulatory text, which is absent here.

Thus, the Proposal cannot establish the new source trigger date because it does not include a proposed rule. The new source trigger date is tied to the date proposed regulatory text is published in the Federal Register.

As a last note, the CAA § 307(d) administrative rulemaking procedures do not expressly require a proposed rule to include proposed rule text. We do not opine on the question of whether a proposed rule subject to CAA § 307(d) provides adequate public notice and an opportunity to comment if it does not include or make available proposed rule text. But that issue is beside the point here because the new source trigger date is defined in CAA § 111(a)(2) and not in CAA § 307(d). So, even if the current proposal satisfies the procedural requirements of CAA § 307(d), it does not set the new source trigger date for the reasons explained above.

11.2 The CRA rescission of the 2020 Policy Rule does not extend to the legal rationale and policy positions used to justify the 2020 Policy Rule and does not endorse the legal and policy interpretations in the preceding 2012 and 2016 rules.

EPA explains that, as one of the three primary elements of the Proposal, it "is taking several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021 under the Congressional Review Act (CRA), disapproving the EPA's final rule titled, 'Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,' 85 FR 57018 (Sept. 14, 2020) ("2020 Policy Rule")." 86 Fed. Reg. at 63110. EPA further explains that:

> Under the CRA, the disapproved 2020 Policy Rule is "treated as though [it] had never taken effect." 5 U.S.C. 801(f). As a result, the preceding regulation, the 2016 NSPS OOOOa Rule, was automatically reinstated, and treated as though it had never been revised by the 2020 Policy Rule. Moreover, the CRA bars EPA from promulgating "a new rule that is substantially the same as" a disapproved rule. 5 U.S.C. 801(b)(2), for example, a rule that deregulates methane emissions from the production and processing sectors or deregulates the transmission and storage sector entirely.

Id. at 63151.

EPA further asserts that, in the legislative history of this CRA action, Congress "rejected the EPA's statutory interpretations of section 111 in the 2020 Policy Rule and endorsed the legal interpretations contained in the 2016 NSPS OOOOa Rule." *Id*. In other words, EPA asserts that the CRA action rescinded not just the 2020 Policy Rule, but also the "statutory interpretations" that stood behind the 2020 Policy Rule. EPA is incorrect.

The CRA applies to "rules." Most importantly, the CRA provides that "[a] ***rule*** shall not take effect (or continue), if the Congress enacts a joint resolution of disapproval" pursuant to CRA § 802. 5 U.S.C. § 801(b)(1) (emphasis added). Similarly, "[a] ***rule*** that does not take effect (or does not continue) … may not be reissued in substantially the same form." *Id*. at § 801(b)(2) (emphasis added). As explained above, the term "rule" is defined to mean "the whole or a part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or describing the organization, procedure, or practice requirements of an agency." 5 U.S.C. § 551(4). When EPA promulgates a final rule, the "rule" is the regulatory text (which imposes legal obligations or creates legal rights) and not the explanation and justification provided in the preamble to the rule. *See also* The Congressional Review Act (CRA): Frequently Asked Questions. Congressional Research Service (Nov. 12, 2021) at 18 (available at https://crsreports.congress.gov/product/pdf/R/R43992).

Thus, a rescission under CRA § 801(b)(1) and the prohibition under CRA § 801(b)(2) on issuing a rule in substantially the same form apply only to the relevant regulatory text and do not apply to EPA's explanation in the administrative record that accompanies the regulatory text. Contrary to EPA's suggestion, the legislative history of this particular CRA action cannot and does not change the plain meaning of the CRA statute. *See INS v. Cardoza-Fonseca*, 480 U.S. 421, 452-3 (1987) (J. Scalia, concurring in the judgment) ("Judges interpret laws rather than reconstruct legislators' intentions. Where the language of those laws is clear, we are not free to replace it with an unenacted legislative intent.").

As a final note, EPA's suggested approach would indiscriminately and inappropriately sweep away legal and policy positions stated in the record of the Policy Rule that are necessary for proper implementation of CAA § 111. For example, EPA explains in the preamble to the final Policy Rule that VOC "are not the type of air pollutant that, if subjected to a standard of performance for new sources, would trigger the application of CAA section 111(d)." 85 Fed. Reg. at 57040. Reversal of this uncontroversial interpretation would cause CAA § 111(d) to have a far broader scope than is reasonable or warranted under the plain text of the statute. Such an outcome is not required or supported by the CRA action.

11.3 API supports EPA's effort to improve and expand the methane emissions control program, however, the cost effectiveness threshold for methane used in the Proposal is not adequately justified.

EPA asserts flexibility as to how cost may be considered in determining BSER in the Proposal. 86 Fed. Reg. at 63154. But the Agency primarily relies on cost effectiveness thresholds expressed in dollars per ton of pollutant reduction. For methane, "EPA finds the cost-effectiveness threshold values up to $1,800/ton of methane reduction to be reasonable for controls that [it has] identified as BSER in this proposal." *Id*. at 63155.

EPA explains that "[u]nlike VOC, [it] does not have a long regulatory history to draw upon in assessing the cost effectiveness of controlling methane, as the 2016 NSPS OOOOa was the first national standard for reducing methane emissions." *Id*. In that 2016 rule, EPA "determined that methane cost-effectiveness values for the controls identified as BSER … range up to $2,185/ton of methane reduction." *Id*. "[B]ecause the cost-effectiveness estimates for the proposed standards in [the Proposal] are comparable to the cost-effectiveness values estimated for the controls that served as the basis (i.e., BSER) for the standards in the 2016 NSPS OOOOa, [EPA] consider[s] the proposed standards to also be cost effective and reasonable." *Id*.

Thus, the only justification the EPA presents for using a methane cost effectiveness threshold of $1,800/ton is that the Agency used a similar methane cost effectiveness threshold in the 2016 NSPS OOOOa rule. That "because we did it before" justification is wholly inadequate in API's view.

CAA § 111 requires that EPA develop a record to support its determination that the NSPS standards "represent[] the best balance of economic, environmental, and energy considerations." *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981). And an agency action is arbitrary and capricious if it does not "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983) (internal punctuation and citations omitted). Here, EPA fails to meet these standards because it presents essentially no "relevant data" to support its proposed cost effectiveness threshold and, because of that, cannot and does not explain how the "relevant data" inform the choice of $1,800/ton.

For example, perhaps EPA believes that using values up to $2,185/ton in the 2016 rule provides evidence that values in this range are acceptable in the current proposal because the 2016 rule has been widely implemented across the affected industry. If this is what EPA believes, it should have said so. But it didn't.

Moreover, EPA has made no effort in the current rule to show why $2,185/ton is an appropriate touch stone, beyond simply asserting it to be true. That failure to present "relevant data" and to explain how those data inform the current proposal fundamentally undermines the proposed value of $1,800/ton. This is particularly important because, even under the Clean Air Act, two "wrongs" do not make a "right." *See New Jersey v. EPA*, 517 F. 3d 574, 583 ("[P]revious statutory violations cannot excuse the one now before the court.").

Lastly, EPA's factual determinations must be "supported by substantial evidence when considered on the record as a whole." *Coalition for Responsible Regulation v. EPA*, 684 F. 3d 102, 122 (D.C. Cir. 2012). The $1,800/ton threshold is supported by no evidence at all, much less substantial evidence.

11.4 API supports appropriate consideration and adequate protection of disadvantaged groups; however, EPA has not adequately explained how the proposed mandatory procedural requirements designed to foster "meaningful engagement" are authorized under the CAA.

EPA has made Environmental Justice a priority in developing the Proposal. For example, EPA made extensive outreach to disadvantaged and potentially overburdened populations and proactively sought to address their concerns in the proposal. EPA also included provisions in the Proposal that are at least partially designed to address Environmental Justice issues. For example, EPA explains that it provided for the use of "cutting edge" technologies in the rule, "alongside a rigorous fugitive emissions monitoring program that is based on traditional OGI technology." 86 Fed. Reg. at 63139. To address the concern of "addressing large emission sources faster," EPA proposes "more frequent monitoring at sites with more emissions." *Id*. And in response to concerns about health impacts, "EPA is proposing rigorous guidelines for pollution sources at existing facilities, methane standards for storage vessels, strengthened and expanded standards for pneumatic controllers, and standards for liquids unloading events that will further reduce emissions." *Id*.

API supports EPA's attention to potential Environmental Justice issues and agrees that the measures described above will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The natural gas and oil industry's top priorities are protecting the public health and safety – regardless of race, color, national origin or income – and the environment. We strive to understand, discuss and appropriately address community concerns with our operations. We are committed to supporting constructive interactions between industry, regulators, and surrounding communities/populations that may be disproportionately impacted.

While API supports EPA's goals, the Agency has not provided sufficient detail in the proposal to allow API to comment in a meaningful way. There is no proposed language to understand the impact of what the Agency intends to do, and other than broad statements that the requirements are authorized under CAA Sections 111(d) and 301(a)(2), no explanation of the substantive legal underpinnings of this concept. We look forward to the opportunity to offer further thoughts on this important topic in comments on the upcoming supplemental proposal.

11.5 Empowering local citizens by providing better access to relevant monitoring data is a worthy goal; however, EPA has not explained the legal basis for establishing a "community monitoring" program as described in the Proposal.

EPA presents a preliminary concept that would "take advantage of the opportunities presented by the increasing use of [advanced methane detection systems] to help identify and remediate large emission events (commonly known as "super-emitters")." 86 Fed. Reg. at 63177. "Specifically, the EPA seeks comment on how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event." *Id*.

API concurs with the importance of identifying and addressing large emissions events. Emissions from such events can be much greater than those from normal operations at a given facility and can result in material economic losses. API's overall support for the Proposal is grounded in a shared interest in seeking to reduce the incidence of such large emissions events.

Having said that, the community monitoring concept presented in the Proposal is novel. To our knowledge, it would be the first time under the CAA that EPA asserts authority to create regulatory obligations for affected facilities based on monitoring conducted by unaffiliated third parties. In concept, this provision would be akin to an LDAR program where an unaffiliated third party does the monitoring and the affected facility then has the legal obligation to address leaks identified by that monitoring. That is a truly new approach under CAA § 111 and the CAA as a whole.

Unfortunately, in describing the concept, EPA does not explain the legal basis for establishing such a provision. That, of course, is essential to understanding whether such a novel provision is legally viable.

We are concerned that EPA does not appear to have such authority. To begin, CAA § 111 calls for standards of performance to be established for emissions sources in regulated source categories. The statute unambiguously specifies that the Administrator shall establish standards of performance for new sources and the states should do so for existing sources. CAA §§ 111(b)(1)(B) and (d)(1). This scheme does not appear to leave room for regulatory obligations to be defined by the actions of third parties.

Moreover, EPA's authority to establish monitoring requirements is limited under CAA § 114 to just four entities: (1) any person who owns or operates any emissions source; (2) certain entities that manufacture emissions control or process equipment; (3) those with information "necessary for the purposes" of CAA § 114; and (4) those "subject to the requirements of this Act." CAA § 114(a)(1). The third parties EPA describes in the Proposal do not appear to fall into any of these four categories.

We note that CAA § 304 expressly prescribes a role for citizens in CAA implementation by authorizing them to file civil lawsuits challenging alleged violations of, among other things, CAA § 111 emissions standards. Congress did not provide similar express language in CAA § 111 or elsewhere in the CAA authorizing the sort of citizen monitoring described in the Proposal. In this context, the absence of such language likely would be construed as a limitation on EPA's authority to allow such monitoring and would not be seen as an implicit delegation of authority from Congress to EPA.

If the Agency decides to actually propose a community monitoring provision in the forthcoming supplemental proposal, we encourage EPA to carefully consider these issues and clearly explain the purported legal basis for any such provision. In addition, EPA must clearly describe important details, such as how the Agency will quality assure third-party monitoring, what monitoring levels are actionable, and the mechanism by which monitoring data are determined to be actionable (*e.g.*, must affected facilities act on data submitted directly to them by third parties, or will EPA or a state regulatory agency determine when the need for action by affected facilities is triggered). And, of course, corresponding proposed regulatory text must be provided.

Lastly, these are complex issues that would benefit from further discussions between EPA, affected facilities, and other interested parties. We encourage EPA to conduct additional outreach on this issue prior to crafting the supplemental proposal. API would welcome the opportunity for a meeting.

11.6 Three proposed "modification" definitions are unlawful because they cover activities that are not a physical change or change in the method of operation of an affected facility that results in an emissions increase.

EPA proposes three equipment or activity-specific modification definitions that encompass actions that are not actually modifications. These must not be included in the final rule.

First, EPA proposes for centralized production facilities ("CPF") that a modification includes (among other things) when "a well sending production to an existing centralized production facility is modified." 86 Fed. Reg. at 63173. Second, EPA proposes that a single storage vessel or a tank battery is modified when (among other things) it "receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from activities such as refracturing a well or adding a new well that sends these liquids to the tank battery)." *Id*. at 63178.

The word "modification" is defined in CAA § 111 to mean "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." CAA § 111(a)(3). Under this definition, two conditions must be satisfied for a modification to occur at a stationary source: (1) there must be a physical or operational change to the source; and (2) that change must result in an emissions increase or the emissions of a new pollutant.

The definitions described above share two flaws. First, a physical change or change in the method of operation is deemed to occur at a given CPF or tank/tank battery, even though no physical or operational change has occurred at that CPF or tank/tank battery. Under these definitions, the relevant physical or operational change occurs at a <u>different</u> affected facility. This plainly does not satisfy the statutory requirement that the modification of a given affected facility must entail a physical change or change in the method of operation at that same facility.

The second flaw with regard to these two definitions is that EPA has not demonstrated that these activities necessarily result in an emissions increase at the given CPF or tank/tank battery. For example, the fact that an upstream well is modified does not necessarily mean that a downstream CPF or tank/tank battery would have an actual emissions increase. More importantly, there is even less likelihood that the downstream operations would have a <u>regulatory</u> emissions increase, given that the Part 60 definition of "modification" requires an increase in the short-term potential to emit of an affected facility. 40 C.F.R. § 60.14(b).

Thus, the modification definitions for CPFs and tank/tank batteries are not consistent with the Act because: (1) they do not require a physical or operational change at the given affected facility; and (2) they presume an emissions increase where such an increase often would not occur.

A third proposed modification definition also is flawed, but for somewhat different reasons. For liquids unloading, EPA proposes that, because "each unloading event constitutes a physical or operational change to the well that has the potential to increase emissions, the EPA is proposing to determine each event of liquids unloading constitutes a modification that makes a well an affected facility subject to the NSPS." 86 Fed. Reg. at 63210. Here, the legal problem is that liquids unloading is necessary at many wells in order to achieve the production potential of the given resource. As such, liquids unloading is part of normal operations for the well and does not constitute a physical or operational change to that well. Moreover, because the regulatory definition of "modification" measures an emissions increase in terms of the short-term potential to emit of the affected facility, it cannot be said that liquids unloading results in an emissions increase.

API acknowledges that the D.C. Circuit has held that the definition of "modification" should be construed expansively. *New York v. EPA*, 443 F. 3d 880, 886-7 (D.C. Cir. 2006). But at the same time, the court recognized that even though the term "modification" is broad, it "cannot bring an activity that is never considered a 'physical change' in the ordinary usage within the ambit of NSR." *Id*. That is the case with liquids unloading.

11.7 EPA may not lawfully determine BSER to include technical infeasibility exceptions because BSER must be technically feasible.

EPA proposes two emissions standards that allow for "technical feasibility" exceptions. EPA proposes "a standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions." 86 Fed. Reg. at 63179. But "[i]n the event that it is technically infeasible or not safe to perform liquids unloading with zero emissions, the EPA is proposing to require that an owner or operator establish and follow BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible." *Id*.

EPA explains that "[a]n 'adequately demonstrated' system needs not be one that can achieve the standard 'at all times and under all circumstances.' Essex Chem., 486 F.2d at 433." *Id*. at 63213. "That said … the EPA recognizes that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible." *Id*.

Similarly, EPA is "proposing a standard under NSPS OOOOb that requires owners or operators of oil wells to route associated gas to a sales line." *Id*. at 63183. "In the event that access to a sales line is not available, [EPA is] proposing that the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions." *Id*. The same standard is proposed for existing sources under Subpart OOOOc. *Id*.

These standards are based on determinations that non-emitting techniques constitute BSER for these sources. At the same time, EPA acknowledges that non-emitting techniques are not always feasible or safe. Alternative standards are provided to cover those situations.

API supports this approach as a practical matter. We agree that non-emitting measures and methods should be used where they are technically feasible and cost effective. But EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. The proposed alternative measures are a common-sense solution.

Having said that, we are concerned that EPA has not asserted an adequate legal basis for taking this approach. In short, the fact that EPA needed to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA § 111.

A "standard of performance" must reflect the degree of emissions limitation "achievable" through application of the best system of emissions reduction that EPA finds to be "adequately demonstrated." CAA § 111(a)(1). The proposed non-emitting standards do not meet this requirement for two reasons.

First, EPA has not demonstrated that techniques that eliminate emissions from liquids unloading events are "demonstrated in practice" for purposes of designating such techniques as BSER. It is true that non-emitting liquids unloading techniques can be used in some circumstances and that associated gas can be routed to a sales line in some situations. But the need to create exceptions under both standards shows that non-emitting techniques are not demonstrated in practice for the full range of regulated activities and circumstances. In effect, EPA seeks to avoid the obligation to show that non-emitting techniques are demonstrated in practice by creating exceptions for situations where non-emitting techniques are not demonstrated in practice.

Second, the proposed non-emitting standards of performance are legally questionable because they are not "achievable," as demonstrated by the need to establish exceptions to make the standard sufficiently practicable. But this bifurcated approach falls short because EPA puts the burden on affected facilities to prove to EPA that they qualify for the exceptions. In other words, the non-emitting standards are presumptively applicable. This approach incorrectly relieves EPA of the burden of promulgating achievable standards in the first instance and improperly defers infeasibility determinations to the time when the rule is implemented and enforced rather than when the rule is promulgated.

Essex Chemical does not support the Agency's approach here. As explained above, EPA points to *Essex Chemical* for the proposition that "[a]n 'adequately demonstrated' system needs not be one that can achieve the standard "at all times and under all circumstances." 86 Fed. Reg. at 63213. But the court was saying something much different than that. The following is a fuller excerpt from the opinion:

> It is the system which must be adequately demonstrated and the standard which must be achievable. This does not require that a sulfuric acid plant be currently in operation which can ***at all times and under all circumstances*** meet the standards; nor, however, does it allow the EPA to set the standards solely on the basis of its subjective understanding of the problem or "crystal ball inquiry."

Essex Chemical Corp. v. Ruckelshaus, 486 F. 2d 427, 433 (D.C. Cir. 1973) (emphasis added). The highlighted portion of this excerpt is what EPA cites. But, in context, it is clear that the court was not saying that BSER may be determined to be "adequately demonstrated" even though the corresponding standard of performance cannot be met "at all times and under all circumstances" by facilities that might become subject to that rule. Instead, the court was saying that EPA does not need to show that a "currently" existing facility (*i.e.*, one in existence when EPA is formulating the rule) can meet the new standard of performance "at all times and under all circumstances."

In other words, the court confirmed that, given adequate justification, EPA may set technology-forcing standards of performance under CAA § 111 – standards that existing facilities would not necessarily be able to meet. This does not support EPA's proposal here to determine that non-emitting techniques are "adequately demonstrated" when it is clear that some significant number of potentially affected facilities will not be able to meet the non-emitting standards.

In sum, CAA § 111 requires BSER to be "adequately demonstrated" and standards of performance to be "achievable." We urge EPA in the upcoming supplemental proposal to provide a better explanation of how setting presumptively applicable non-emitting standards with a case-by-case "off ramp" satisfies these statutory requirements.

11.8 EPA should not define and impose practical enforceability requirements without first developing a coherent approach for all EPA programs.

EPA proposes "to include a definition for a 'legally and practicably enforceable limit' as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules." 86 Fed. Reg. at 63201. "The intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy." *Id*.

API believes that improving the clarity of the storage vessel applicability criteria is a worthwhile effort. However, the question of what constitutes an acceptable and effective "legally and practicably enforceable limit" goes well beyond the four corners of this regulation and has implications far beyond this narrow regulatory provision. This question is relevant across EPA's Clean Air Act stationary source programs: from major source permitting under NSR/PSD, to the Title V operating permit program, to all manner of federal and state emissions control programs (of which CAA § 111 is just one).

And, what constitutes an acceptable and effective "legally and practicably enforceable limit" has been an open question since the mid-1990s, when the prior "federal enforceability" requirement was remanded or vacated across EPA's programs. *See*, *National Mining Ass'n v. EPA*, 59 F. 3d 1351 (D. C. Cir. 1995); *Chemical Mfrs. Ass'n v. EPA*, 70 F. 3d 637 (D.C. Cir. 1995); *Clean Air Implementation Project v. EPA*, 1996 WL 393118 (1995). EPA announced its intent to conduct a comprehensive rulemaking to address the holdings in these cases, but has not yet taken action almost 30 years after the decisions were handed down. Memorandum from John S. Seitz to Regional Office Addressees, *Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit* (Jan 22, 1996) at 1.

With this as a backdrop, it is commendable for EPA to propose to clarify applicability of the storage vessel emissions standards by defining the term "legally and practicably enforceable limit." But this issue has implications that go far beyond the narrow confines of the storage vessel standard. Addressing it in a piecemeal, rule-by-rule fashion will ultimately cause confusion and potential inconsistency across the relevant programs. Further, it could inadvertently call into question existing permitting and regulatory regimes that do not specifically include the parameters proposed by EPA.

Moreover, affected facilities and states now have years of experience implementing the Subpart OOOO and OOOOa storage vessel standards, including substantial experience in crafting appropriate emissions limitations to govern applicability of these standards. Creating new mandatory procedural requirements is unnecessary, given that no systemic problem has emerged during this long implementation period. Such requirements would add to the cost and burden of implementing these standards without delivering any commensurate benefit.

Therefore, we suggest that EPA defer final action on the proposed definition until such time as the Agency undertakes a broad-based rule that would provide a single, consistent approach across all affected CAA programs.

11.9 The requirement to use "non emitting" equipment or methods does not constitute a "zero emissions" numeric standard.

Numerous times in the Proposal EPA describes non-emitting equipment or work practice standards as "zero-emissions" standards. For example, for liquids unloading, EPA is "proposing a standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions."). 86 Fed. Reg. at 63179. For pneumatic controllers, EPA is "proposing a requirement that all controllers (continuous bleed and intermittent vent) in the production and natural gas transmission and storage segments must have a methane and VOC emission rate of zero.". *Id*. at 63202.

As a practical matter, the term "zero-emissions" is apt because the object of these proposed standards is to eliminate methane and VOC emissions from the affected facility. But as a legal matter, the term "zero-emissions" is imprecise and in error because these standards impose equipment or work practice obligations and do not impose a numeric emissions limitation of zero.

The legal distinction is important because a fully compliant pneumatic controller or liquids unloading event may still have incidental VOC and methane emissions. No piece of equipment or work practice is perfect – even if implemented according to best practices. Thus, the term "zero-emissions" expresses an idealized outcome that is belied by reality. A zero-emissions numeric standard would unreasonably cause incidental emissions to be a violation of the standard. EPA should correct its terminology in the Final Rule by stating that non-emitting control measures under this rule are work practices.

11.10 Emissions due to noncompliance should not be treated as "fugitive emissions" under the rule as proposed.

EPA proposes that the term "fugitive emissions component" should include "[c]ontrol devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, State rule, or permit." *Id*. at 63170. EPA asks for comment "on the use of the fugitive emissions survey to identify malfunctions and other large emission sources where the equipment is not operating in compliance with the underlying standards, including the proposed requirement to perform a root cause analysis and to take corrective action to mitigate and prevent future malfunctions." *Id*.

This proposal to expand the definition of "fugitive emissions component" to include emissions from control devices not operating in compliance with applicable rules must be clarified. All other equipment included in the definition of "fugitive emissions component" is not expected to leak (at least in any significant amount). As a result, when periodic leak monitoring is conducted, the goal is to discern the presence of a leak.

In contrast, even well operating emissions control devices and flares will have a permissible level of emissions. Thus, a periodic LDAR-type emissions survey should be expected to detect some amount of methane or VOC emissions.

That raises the question of what amount of emissions triggers the need for further action under the LDAR work practices, such as investigation and corrective action? The conceptual answer is an amount that represents noncompliance with applicable emissions or work practice standards. But the Proposal does not describe a mechanism for determining what level of emissions corresponds to compliant conditions and how to determine the increased amount that represents actionable noncompliance. In other words, the rule does not define what constitutes a "leak" for purposes of emissions control devices or flares. To be workable, EPA must include such details in the final rule.

We note that an operator cannot tell whether a control device is meeting its designed control or destruction efficiency (often 95 or 98 percent) through use of an OGI camera because an OGI camera does not quantify emissions. Thus, it is not possible to determine from an OGI survey whether a control device is operating at its required efficiencies. At best, an operator may be able to obtain information from an OGI camera that suggests further investigation may be necessary to determine whether a device is functioning as intended. But even this limited concept would pose significant questions as to how it might be implemented (*e.g.*, permissible emissions from a control device often vary considerably due to variable loading).

In addition, OGI and M21 are not even feasible for flares. EPA needs to explain how these methods would apply or, conversely, prescribe acceptable and workable alternative methods.

For these reasons, we urge the Agency in the upcoming supplemental proposal to explain further how the LDAR program would apply to emissions control devices and flares.

11.11 When work practice standards are fully implemented, emissions addressed by those standards cannot constitute a "violation."

EPA suggests in the Proposal that, when a leak is detected in a closed vent system during a fugitive emissions survey, "the emissions would be considered a potential violation of the no detectable emissions standard." *Id*. This is a variation of the "zero-emissions" issue described in Section 1.9, above. The "no detectable emissions standard" is a work practice standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as detectable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. EPA has presented no reason in the Proposal to depart from its historical approach with regard to fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in compliance when a leak is detected, as long as the associated work practices requiring investigation and repair are followed.

11.12 The proposal fails to explain and appropriately reconcile the applicability of Subparts OOOO, OOOOa, OOOOb, and OOOOc.

The Proposal is notably silent on the question of how to reconcile the applicability of the three new source NSPSs and the existing source program. The only clues as to EPA's thinking are the proposed applicability dates for the various subparts. For example, Table 1 lists the applicability dates for the new source standards (Subparts OOOO, OOOOa, and OOOOb) for new, modified or reconstructed sources that trigger these rules. 86 Fed. Reg. at 63117. Similarly, Table 1 indicates that the Subpart OOOOc existing source program applies to sources in existence on or before November 15, 2021. *Id*.

These dates alone do not adequately explain how EPA proposes to apply the rules. For example, the Proposal could be interpreted such that sources already subject to Subpart OOOO or OOOOa as of November 15, 2021 become "existing sources" on that date and will be subject to the Subpart OOOOc existing source program.

On the other hand, the Proposal could be interpreted such that sources already subject to Subpart OOOO or OOOOa as of November 15, 2021, are "new sources" under those rules and, therefore, they are not somehow transformed into "existing sources" on November 15, 2021.

This applicability issue is further clouded by the fact that Subpart OOOO applies only to VOCs, Subparts OOOOa and OOOOb apply to VOCs and GHGs, and Subpart OOOOc applies only to methane. Thus, if EPA intends that all sources for which construction, reconstruction, or modification is commenced prior to November 15, 2021, should become existing sources subject to Subpart OOOOc, that outcome would apply only for purposes of GHGs. To the extent such sources already were subject to Subpart OOOO or OOOOa, they would continue to be subject to those subparts for purposes of VOCs.

API has two recommendations on these issues. First, in the upcoming supplemental proposal containing proposed regulatory text, EPA must clearly propose how it intends to reconcile applicability of the various subparts. Applicability is a critical issue that cannot be left unaddressed or ambiguous.

Second, API recommends that there is only one permissible approach under CAA § 111, which would be comprised of two basic rules. First, a "new source" that is subject to Subpart OOOO, OOOOa, or OOOOb cannot be subject to the Subpart OOOOc existing source program. Second, and by extension, the Subpart OOOOc existing source program applies only to sources that were not subject to Subpart OOOO or OOOOa as of November 15, 2021[71] – i.e., the Subpart OOOOc existing source program applies only to sources that were not regulated by a relevant subpart as of November 15, 2021.

This outcome is required by two provisions in CAA § 111. First, the term "new source" is defined to mean "any stationary source, the construction or modification of which is commenced after the publication of regulation (or, if earlier, proposed regulation) prescribing a standard of performance under this section which will be applicable to such source." CAA § 111(a)(2). Because Subparts OOOO and OOOOa are "regulations" that "prescribed standards of performance" for affected facilities at "stationary sources," any affected facilities under Subparts OOOO or OOOOa unambiguously must be "new sources" under this definition. It does not matter that EPA has promulgated (and plans to promulgate) successive versions of the new source standard and it does not matter that the proposed Subpart OOOOc existing source program post-dates Subparts OOOO and OOOOa. Under the plain terms

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[71] API explains above that November 15, 2021, is not a permissible trigger date for Subparts OOOOb and OOOOc because the Proposal is not actually a proposed rule. API neither waives that position nor concedes that point here.

of the statutory definition of "new source," affected facilities under Subpart OOOO or OOOOa are "new sources.

Second, this point is driven home by CAA § 111(d), which states (in relevant part) that EPA shall prescribe regulations establishing a program for "any existing source … to which a standard of performance under this section would apply if such existing source were a new source." CAA § (d)(1)(A). This provision unambiguously directs that a CAA § 111(d) existing source program may apply only to an existing source that is not subject to a standard of performance for new sources. This necessarily follows from the definition of "new source."

11.13 EPA is not authorized to approve state existing source emissions limitations that were not derived using the required CAA § 111 standard-setting methods.

EPA proposes "[t]o the extent a State chooses to submit a plan that includes standards of performance that are more stringent than the requirements of the final EG, States have the authority to do so under CAA section 116, and the EPA has the authority to approve such plans and render them Federally enforceable if all applicable requirements are met. Union Electric Co. v. EPA, 427 U.S. 246, (1976)." 86 Fed. Reg. at 63251. EPA notes that "in the Affordable Clean Energy (ACE) rule, it previously took the position that Union Electric does not control the question of whether CAA section 111(d) State plans may be more stringent than Federal requirements." *Id*. But EPA "no longer takes this position." *Id*. "[B]ecause of the structural similarities between CAA sections 110 and 111(d), CAA section 116 as interpreted by Union Electric requires the EPA to approve CAA section 111(d) State plans that are more stringent than required by the EG if the plan is otherwise is compliance with all applicable requirements." *Id.* at 63251-2.

EPA further explains that "CAA sections 111(d) and 110 are structurally similar" and that "[r]equiring States to enact and enforce two sets of standards, one that is a federally approved CAA section 111(d) plan and one that is a stricter State plan, runs directly afoul of the court's holding that there is no basis for interpreting CAA section 116 in such manner." *Id.* at 63252. EPA concludes by noting that "its authority is constrained to approving measures which comport with applicable statutory and regulatory requirements. For example, CAA section 111(d) only contemplates that State plans include requirements for designated facilities, therefore the EPA believes it does not have the authority to approve and render federally enforceable measures on other entities." *Id*.

As EPA notes, the Agency took the diametrically opposite position in the ACE rule. "In response to commenters who contend the EPA does not have the authority to approve more stringent state plans," EPA agreed that the comments have merit. 84 Fed. Reg. 32520, 32559 (July 8, 2019). EPA provided a detailed explanation:

> [T]he Court's decision in Union Electric on its face does not apply to state plans under CAA section 111(d). The decision specifically evaluated whether the EPA has the authority to approve a SIP under section 110 that is more stringent than what is necessary to attain and maintain the NAAQS. The Court specifically looked to the requirements in CAA section 110(a)(2)(A) as part of its analysis, a provision that is wholly separate and distinct from CAA section 111(d). CAA section

> 110(a)(2)(A) requires SIPs to include any assortment of measures that may be necessary or appropriate to meet the ‘‘applicable requirements’’ of the CAA, which largely relate to the attainment and maintenance of the NAAQS. CAA section 111(d), by contrast, directs state plans to establish standards of performance for existing sources that reflect the degree of emission limitation achievable through the application of the BSER that EPA has determined is adequately demonstrated—and CAA section 111(d) expressly provides that it cannot be used to regulate NAAQS pollutants. Because the Court’s holding was in the context of section 110 and not CAA section 111(d), the EPA believes that Union Electric does not control the question of whether CAA section 111(d) state plans may be more stringent than federal requirements.

Id. at 32560.

To sum up, two years ago EPA asserted that *Union Electric* <u>is not</u> applicable to state plans submitted under CAA § 111(d) because that case dealt only with state emissions standards adopted under CAA § 110. Moreover, emissions standards prescribed by CAA § 111 are materially different than state implementation plans submitted under CAA § 110. The former must be based on BSER, which is narrowly and precisely defined in the Act. The latter must be designed to satisfy minimum statutory requirements designed to achieve the broader air quality goals of attaining and maintaining compliance with the NAAQS.

Today, EPA proposes that *Union Electric* <u>is</u> applicable to state plans submitted under CAA § 111(d) because that provision and CAA § 110 are “structurally similar in that States must adopt and submit to the EPA plans which include requirements to meet the objectives of each respective section.” 86 Fed. Reg. at 63252. EPA notes that the *Union Electric* court was concerned that, if more stringent state programs could not be approved under CAA § 110, then states that wanted to be more stringent would need to have two sets of regulations in place – a less stringent EPA-approved version and a more stringent state-only-enforceable version. The court concluded that such an approach was not warranted because it would impose “wasteful burdens” on EPA and the states. EPA argues that the same rationale equally applies to state CAA § 111(d) programs.

These opposing views are easily resolved by looking at what the court actually said in *Union Electric*. That case involved a 1972 Missouri state implementation plan (“SIP”) for sulfur dioxide. *Union Electric Co. v. EPA*, 427 U.S. 246, 252 (1976). A local utility filed a challenge to that SIP claiming that the SIP was invalid because it imposed technologically and economically infeasible emissions control requirements. *Id*. at 253.

The court upheld the SIP on the grounds that “Congress intended claims of economic and technological infeasibility to be wholly foreign to the Administrator’s consideration of a state implementation plan.” *Id*. at 256. More specifically, the court interpreted “the ‘as may be necessary’ requirement of § 110(a)(2)(B) to demand only that the implementation plan submitted by the State meet the ‘minimum conditions’ of the [1970 CAA] Amendments.” *Id*. at 264. “Beyond that, if a State makes the legislative determination that it desires a particular air quality by a certain date and that it is willing to force technology to attain it – or lose a certain industry if attainment is not possible – such a determination is fully consistent with the structure and purpose of the Amendments, and § 110(a)(2)(B) provides no basis for the EPA Administrator to object to the determination on the ground of infeasibility.” *Id*. at 265.

Thus, the court expressly held (as EPA observed in 2019) that CAA § 110(a)(2)(B) allows states to adopt more stringent programs than minimally required by the Act. In that context, its observation that CAA § 116 should not be read as only authorizing more stringent state-only emissions control programs, *id.* at 264, is limited to programs such as CAA § 110 that, in the first instance, allow states to adopt more stringent measures than minimally required under the Act.

Here, CAA § 111(d) unambiguously requires state existing source programs to prescribe "a standard of performance," which is defined to mean "a standard for emissions of air pollutants which reflects the degree of emissions limitation achievable through the application of the best system of emissions reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." CAA §§ 111(d)(1)(A) and 111(a)(1). There is no room for states to do anything more than prescribe standards of performance that reflect BSER. Thus, in sharp contrast to CAA § 110, CAA § 111(d) does not prescribe "minimum conditions" that may be exceeded by the states. Instead, CAA § 111(d) requires standards of performance that must reflect a BSER determination that is based, among other things, on consideration of costs and feasibility. If proposed state standards of performance do not meet these requirements, they must be rejected by EPA.

Therefore, "structural similarities" between CAA §§ 110 and 111 do not provide an adequate basis for EPA's proposal that it may approve state standards of performance that are more stringent than required by CAA § 111(d). Such an approach unreasonably and unlawfully ignores the significant substantive differences between CAA §§ 110 and 111 and would violate the unambiguous requirement that state § 111(d) standards of performance must reflect BSER.

To be clear, API supports the coordination and consolidation of federal and state emissions control requirements for the oil and gas sector. Ideally, only one set of standards would apply – state devised and administered emissions control programs that simultaneously satisfy CAA § 111 requirements and address any unique state priorities and objectives. We believe there is sufficient latitude under CAA § 111(d) to allow for EPA approval of state programs in most cases because, in our experience, state programs are typically grounded in principles that would satisfy CAA § 111 standard setting criteria.

But it is at least theoretically possible that a state would seek to impose emissions control obligations that go so far beyond CAA § 111 principles that such obligations cannot be squared with the federal CAA requirements. In such cases, states have authority under CAA § 116 to implement their programs as a matter of state law. But there is no authority under CAA § 111 or 116 for EPA to federalize such state programs.

Attachment A

API Comments on Prepublication Draft Appendix K – Protocol for Using Optical Gas Imaging to Detect Volatile Organic Compound and Greenhouse Gas Leaks

API Comments on Prepublication Draft
Appendix K – Protocol for Using Optical Gas Imaging to Detect Volatile Organic Compound and Greenhouse Gas Leaks[1]

I. General Comments on Proposed Appendix K Draft

1. API supports use of Optical Gas Imaging (OGI) technology because of its potential to reduce equipment leak emissions at a lower cost than through use of traditional methodologies. However, significant modifications are necessary to the proposed Appendix K protocol.

API has worked diligently with EPA to integrate OGI monitoring into rules and to develop the specifics of the methodology. These comments are intended to foster a high-quality generic methodology for use at facilities with large process operations.

API believes significant modifications (as offered herein) to the proposed Appendix K are necessary before it could effectively be implemented for use across downstream oil and gas facilities or other process industries. API's recommended changes are intended to proactively address concerns that the proposed requirements:

1) will result in difficulty in finding and retaining, adequate numbers of qualified senior OGI operators;

2) that the monitoring, training and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and

3) that the ownership of various requirements, and particularly the recordkeeping requirements, are unclear and unnecessarily burdensome.

API's recommended changes also aim to make the Appendix K requirements more straightforward and efficient.

2. Appendix K requirements, even if revised, are not appropriate for most upstream and midstream operations characterized by a great many small, geographically dispersed and often remote facilities, with a limited number of fugitive equipment components.

Appendix K as drafted is unnecessarily burdensome and ineffective for utilization in upstream production facilities, gathering and boosting compressor stations, and transmission compressor stations as discussed in the main body of API's comments on this proposal[2]. OGI protocols for these facilities

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[1] Posted at https://www.epa.gov/system/files/documents/2021-11/40-cfr-part-60-appendix-k-proposal_0.pdf

[2] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review: Proposed Rule 86 *Fed. Reg*. 63110 (November 15, 2021)

should continue to be based on part 60 subpart OOOOa requirements, not Appendix K. The requirements specified in subpart OOOOa that are currently used by operators have consistently proven to be effective and are more appropriate for use in upstream applications.

Appendix K goes beyond the current subpart OOOOa requirements concerning performance specifications, operating envelope, survey time, and records for leaking components and is impractical for upstream operators to implement given the hundreds to thousands of well sites and compressor stations to monitor, the geographic dispersion of these facilities and the lack of on-site resources.

3. Appendix K methodology may be suitable for large, complex process operations in other industries.

A. Proposed Appendix K provides a protocol for performing OGI surveys at complex process operations, such as refineries. It is potentially applicable, with the changes we are recommending, not only for refineries and gas plants, but for many similar, complex processes. On promulgation of Appendix K, permitting authorities are likely to immediately begin requiring its use for a variety of such processes. Furthermore, if the final methodology is resource and cost efficient, many facility owners or operators will apply for approval to use OGI as an alternative to current Method 21 monitoring.

Since the proposed Appendix K clearly identifies in proposed paragraphs 6.1.1 and 6.1.2 where a particular OGI camera is sensitive enough to find leaks and rulemaking or Administrator approval would be needed to allow use of OGI for a process not covered by the current rulemaking, it seems counterproductive to include in Appendix K itself a limitation to only oil and gas source categories. Thereby preventing or delaying, others from realizing the benefits of using OGI. We provide additional specifics and our recommendations in Comment II.2.

B. Assuming reasonable frequency and repair requirements are proposed and our suggested revisions to the proposed Appendix K are implemented, we recommend EPA proceed expeditiously to amend part 63 subpart CC (RMACT 1) to allow use of OGI technology and Appendix K as an alternative to Method 21 for refineries. In the recent Refinery Sector Rulemaking, EPA proposed allowing for use of OGI as an alternative to Method 21, but did not finalize that proposal because “we have not yet proposed appendix K.”[3] Adding OGI as an alternative to RMACT 1 would significantly reduce the refinery and Agency resources associated with preparing and reviewing Alternative Method of Emission Limitation or Alternative Monitoring requests to allow OGI for those facilities and allow refineries to take advantage of the improvements inherent in Appendix K versus the currently available leak detection and repair (LDAR) Alternative Work Practice (AWP) in Part 60 Subpart A (§60.18(g), (h) and (i)).

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[3] 80 *Fed. Reg.* 75191 (December 1, 2015)

4. Resource constraints could make OGI using Appendix K impractical and inefficient.

A. The proposed Appendix K protocol imposes overly burdensome monitoring, training, auditing and other QA/QC requirements that reduces the hours a camera operator can spend monitoring and extends the time it takes to qualify or requalify a camera operator. Training requirements associated with the Appendix K protocol could be reduced in API's view without sacrificing the effectiveness of emission detection efforts.

Additionally, Appendix K requires a senior OGI camera operator to train and oversee other OGI camera operators and in some cases to take videos of monitoring operations, requiring at least a senior operator for every 5-10 OGI camera operators doing actual monitoring. This is a problem for any user of Appendix K. We discuss this in more detail in paragraph B of this comment and throughout these comments.

The establishment of significant and excessive overhead by the proposed Appendix K compared to part 60 subpart OOOOa and other current OGI monitoring requirements reduces the economic advantage for moving to this alternative. OGI technology offers the potential to play a significant role in reducing methane and VOC emissions, reducing leak durations and lowering the cost of monitoring. Imposing additional overhead does not significantly increase leak detection and repair effectiveness, but does increase costs and inefficiencies.

B. A senior OGI camera operator is defined in Section 3.0 of the proposed Appendix K as a "camera operator who has conducted OGI surveys at a minimum of 500 sites over the entirety of their career, including at least 20 sites in the past 12 months, and has completed or developed the classroom, computer or on-line camera operator training as defined in Section 10.2.1."

Paragraph 10.2.2 requires a senior OGI operator to:

- conduct 10 surveys while being observed by a trainee,
- conduct 40 side -by-side surveys with each trainee,
- observe 50 surveys performed by the trainee, and
- perform a follow-up survey as a final test of a new trainee.

Thus, the senior OGI operator is tied up for the duration of trainee classroom training and for 101 surveys per trainee. Additionally, there are proposed quarterly performance audit requirements, which would require at least a day (two 4-hour surveys) of a senior OGI operator's time for each operator being audited. There will be a huge demand for senior OGI operators, and those operators will be doing training and audits rather than monitoring for leaks. While we recommend reasonable reductions in these individual duties that would still assure well-trained OGI camera operators conduct monitoring surveys, we believe the demand for senior OGI camera operators will exceed supply for the foreseeable future and will be an on-going challenge. Conceptually, our desire is to have our most experienced camera operators monitoring for leaks a significant portion of their time, not spending all their time training or auditing. That can only be accomplished if there is an adequate supply of such senior people and if those senior people have enough field monitoring time to keep their skills sharp.

We therefore recommend that, in addition to reducing the time senior operators must spend on training and auditing, the criteria for the senior OGI operator designation be revised. As we specifically address throughout these comments, we believe the functions planned for this operator category can be performed by OGI camera operators with a reasonable amount of current field experience, and such a change in the senior operator criterion will assure enough qualified people will be available to perform the necessary training and auditing functions. Furthermore, the resulting larger pool of senior operators would permit rotating personnel efficiently through monitoring, training and audit functions.

To accommodate this change, we suggest a revised definition of senior "OGI camera operator" in Comment II.6, which removes the requirement as to the career experience of the individual and converts the 20-site current experience requirement to 100 hours.

5. Use of drones as an OGI camera platform

Drones are currently being developed, and in some cases, being used to perform OGI monitoring. They are particularly useful and efficient for monitoring dispersed small sources (e.g., in tankfields) and elevated, hard to reach equipment. **We request that the rulemaking clarify that use of drones is allowed if Appendix K requirements are met and, as discussed in Comment II.1, by removing the limitation in Appendix K that the camera be "hand-held."** While the type of mount needs to be considered in determining if a separate operating envelope is needed for camera configurations used with that mount, this clarification should make it clear that if operating envelope, dwell time and related requirements appropriate for a particular camera model and configuration are met it does not matter how the camera is mounted. **To affect this clarification, we recommend drones be included as an example of a camera platform in the definition of camera configuration and in proposed paragraph 8.3.**

6. While not appropriate for inclusion in Appendix K, fixed continuous monitors should be addressed in referencing rules where appropriate.

In some situations, continuous leak monitoring systems are justified and starting to be used instead of periodic monitoring with portable OGI cameras. As discussed in the main body of these comments, where such systems might be desirable for some situations, the referencing subpart (in this case proposed subparts OOOOb and OOOOc) should address that approach as an alternative to periodic OGI monitoring.

II. Specific Comments and Recommendations on Appendix K

1. General Terminology

A. The OGI camera addressed by Appendix K is identified as a “hand-held, field portable infrared camera” throughout the proposal. Field portable cameras that are capable of being hand-held are sometimes mounted on tripods (as indicated in the draft definition of “Camera Configuration” and elsewhere in the proposal) or mounted on a drone, or are set down on a surface or mounted on a harness worn by the operator; those variants could be interpreted as not being “hand-held.” Since operating envelopes can be developed for any of these mounting approaches, we believe it is more appropriate to specify that Appendix K addresses “field portable infrared cameras,” and that it is unreasonable and adds significant inefficiency to require that the camera be hand-held. **We therefore recommend the modifier “hand-held” be deleted from Appendix K everywhere it occurs as a OGI camera descriptor.** Use of the term as an example of an OGI camera operating condition (e.g., in the definition of “Camera Configuration”) is appropriate and need not be deleted, though we suggest “drone” be added as an alternative example of a camera mount in those two cases where “hand-held” and “tripod” are identified as example camera mounts.

B. Many places in Appendix K refer to “regulated components.” But there will be locations where there are components regulated under other rules (e.g., a HON process unit located within a refinery) or by non-equipment leak portions of the referencing rule or permit (e.g., process vents) that might be within an OGI’s operating envelope. **Thus, for clarity, we recommend the term “regulated components” be changed to “equipment leak components regulated by the referencing subpart or permit.”**

C. In the petroleum operations that Appendix K would apply to under the current proposal[4] and in other operations it may apply to under other rules or permits, a “site” can be anything from a single piece of equipment involving a few potential leak interfaces to a refinery complex involving millions of potential leak interfaces. Thus, monitoring a “site” can take a brief time for one OGI operator (minutes or hours) or require many fulltime OGI operators and take months to complete. Because of this extreme diversity, **API recommends “site” not be the basis for any Appendix K requirements, except where the size of the site is not significant** (e.g., the requirement in Section 9.0 that each “site” have a monitoring plan)**.** Specific suggestions for alternatives to each use of “site” in the draft Appendix K where we believe a change is needed are included below and in the redline version of the proposed Appendix K we have included with these comments.

Additionally, there are requirements assigned to the “site” that could be the responsibility of a contract monitoring organization and could apply at multiple sites. For instance, development of procedures that describe how components will be viewed with the OGI camera (paragraph 9.4) and the requirement to have a plan for avoiding camera operator fatigue (paragraph 9.5). **In these cases, we are recommending that Appendix K provide that the various requirements assigned to the site be either**

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[4] Ibid.

reassigned or flexibility be provided to allow a more appropriate assignment of responsibility and to reduce unnecessary or duplicative recordkeeping requirements.

D. “Number of surveys” performed is a proposed criterion for an operator to be a senior OGI operator, for establishing training requirements and is a criterion for other proposed requirements. Given that an individual site survey can take hours or months depending on the size and complexity of the site, basing any requirement or criterion on the “number of surveys” creates confusion and inequities. In our specific comments below, **we recommend use of hours of monitoring or, in some cases, the “number of 20-minute monitoring periods” as a more precise and easily managed substitute for “number of surveys.”**

E. In setting requirements based on “sites” or “number of surveys” there is a lack of clarity as to whether the requirements require each site to be a different site or each survey to be of a separate set of equipment. This concern would carry over if, as we recommend, the criterion is changed to a monitoring time basis. It would be burdensome and wasteful to interpret these requirements as requiring monitoring of different equipment and, in some cases, it would be infeasible to meet such an interpretation. **We recommend EPA clarify that such requirements do not require monitoring of different equipment for every survey, and we have recommended clarifying language in some of our specific comments and in our redline version of the proposed Appendix K.**

F. Initial training requirements for OGI operators is referred to as “classroom” training throughout proposed Appendix K. Most training today is done through electronic media, often through web-based on-line modules. Use of the word “classroom” could be interpreted to disallow such common training approaches and instead mandate in person classroom attendance. Such a strict limitation creates inefficiencies, is inconsistent with modern training approaches and potentially limits the rate at which new operators can be trained. **API requests the word “classroom” be deleted or revised everywhere it is used.** In some uses we believe the meaning is unchanged by this deletion, but where necessary we suggest the term “classroom, computer or on-line” be used instead.

2. Paragraph 1.3 Applicability Belongs in a Referencing Subpart, Not in A Test Protocol

A. Paragraph 1.3 starts “This protocol is applicable to all facility types from the upstream and downstream oil and gas sectors and may apply to well heads, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities when referenced by an applicable subpart.” Consistent with the application of Appendix K to other source categories in the near term, the precedent of leaving applicability decisions to referencing subparts and permits, and API’s belief that Appendix K is inappropriate for many of the upstream operations listed, we see no purpose for including this sentence in Appendix K. Nor does it reflect that the protocol addresses equipment leaks, as would be normal for an EPA method. **API, therefore, recommends this sentence be revised to the following: “This protocol is applicable to equipment leak components at facilities when referenced by an applicable subpart.”**

B. Paragraph 1.3 states "This protocol is not applicable to chemical plants or other facility types outside of the oil and gas upstream and downstream sectors." **We recommend this sentence be deleted.** Appendix K is appropriate for use for some processes in other source categories and there is no reason to preclude that here since Appendix K only becomes applicable when a referencing subpart, permit or the Administrator allows and since adequate camera capability is assured by the requirements in proposed Paragraphs 6.1.1 and 6.1.2.[5] and the other Appendix K requirements.

For instance, there are many Hazardous Organic NESHAP (HON) processes, including within some refineries (e.g., benzene, toluene, xylene (BTX) units), where Appendix K would be immediately useable, with appropriate approvals. There is no reason to preclude the use of OGI and Appendix K, and to forgo any potential emission reductions or efficiencies, for those HON processes where the camera has adequate capability by having this sentence present in Appendix K. Similarly, Appendix K could, with appropriate approvals, be used for Ethylene Production source category units, another type of unit often found within or adjoining a refinery. Deleting this sentence now, would save having to amend Appendix K in the near future, when the first non-oil and gas rule is proposes to allow OGI, or a regulatory authority wishes to require its use for other source categories.

While there will be processes in a chemical or other source category where OGI and Appendix K would not fit, there are many places where it does and the use of OGI in those cases should be encouraged. Assurance that Appendix K is not being misapplied can be further achieved by being specific in the referencing subpart or permit as to process chemistry that must be present to use OGI and Appendix K, or through the permit or Administrator review where it is requested to be used for sources not covered by a referencing subpart. The purpose of part 60 appendices is to provide generic methodologies that do not have to be amended each time they are referenced, and we encourage the Agency to align the Appendix K applicability section with that purpose.

3. Definition of "Fugitive Emission or Leak"

The proposed definition of fugitive emission or leak is "any emissions observed using OGI." **API believes that the definition can only address emissions from equipment components identified in the referencing subpart or permit as being subject to OGI.** Those are the only emission sources that were considered in the referencing subpart rulemaking or permitting process and are the only components that the referencing subpart or permit monitoring and repair provisions address. We agree that other OGI findings must be addressed if the monitoring identifies excess emissions or unauthorized emissions, but such findings are subject to other repair and reporting requirements than those a referencing subpart or permit imposes for equipment leaks.

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[5] 6.1.1 The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition

6.1.2 The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr.) and butane emissions of 18.5 g/hr. at a viewing distance of 2 metersand a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less.

We recommend the following revised definition.

> ***Fugitive emission or leak*** **means any emissions observed using optical gas imaging from any equipment component identified in the referencing subpart or permit as being subject to monitoring using this Appendix (Appendix K).**

4. Definition of "Repair"

Appendix K appropriately requires that when a leak is identified by OGI monitoring, that the leaking component be clearly identified. However, Appendix K does not address repair. Repair requirements are addressed in the referencing subpart or permit, and the referencing subpart or permit may provide alternatives to adjusting or altering the leaking component, the only approach mentioned in the proposed Appendix K definition of repair. For instance, it may be possible and allowed to route the leak to a compliant control device. Additionally, the referencing subpart will have its own definition of repair and will address how it is to be demonstrated that the repair was successful. For instance, it could require remonitoring by OGI or it could require remonitoring by OGI or Method 21. **Because repair is addressed in each referencing subpart or permit and not in Appendix K, and the definition in that subpart or permit may be different from the definition proposed here, this proposed definition should be deleted.**

5. Definition of "Response Factor"

The proposed definition of "response factor" is:

> *Response factor* means the OGI camera's response to a compound of interest relative to a reference compound at a concentration path-length of 10,000 part per million-meter. Response factors can be obtained from peer reviewed articles or may be developed according to procedures approved by the Administrator.

The second sentence of this proposed response factor definition limits response factors to those obtained from peer reviewed articles or developed according to procedures approved by the Administrator. However, there are serious issues with that limitation as discussed below. We believe that the criteria in the first sentence of the proposed definition and in paragraph 6.1.1 of the proposed Appendix K are adequate to assure valid response factors. Therefore, **API recommends that the second sentence of the proposed definition be deleted.**

The first issue is that there may be different response factors for different OGI cameras as technology changes and new response factors will be needed as additional applications of OGI are made. Such commercial information is not amenable to publication in peer reviewed articles, nor could such response factors be published in a timely manner. Thus, if anything is to be peer reviewed it must be the methodology used to develop the response factors. Given the specifics in the first sentence (a path-length of 10,000 ppm-meters) and the specification in proposed paragraph 6.1.1 of propane as the reference compound, it hardly seems necessary to require any review of the response factors themselves.

Secondly, hundreds of response factors have been developed by camera manufacturers for current cameras. We are concerned that those response factors, which are currently in widespread use, might not meet the criteria in the proposed definition. While these factors may have been peer reviewed, they were not necessarily "obtained from peer reviewed articles." Furthermore, we have no idea what procedures the Administrator might require and whether currently used factors will be found to be consistent with that yet undefined procedure.

If the Agency believes such a limitation is needed, it should focus the limitation on the methodology for developing response factors, propose the methodology they plan to require when the final Appendix K language is proposed, provide for automatic approval after 90 days of any response factor or response factor methodology submitted to the Administrator if no action is taken within that time and grandfather response factors developed prior to the proposal of the Administrator's methodology.

6. Definition of "Senior OGI Camera Operator"

A. Some OGI camera operators are certified thermographers. The thermographic certification requirements for a Level 2 thermograph operator parallel the initial and refresher OGI training requirements that would apply under Appendix K. Thus, **we recommend that certified thermographers be considered as senior OGI camera operators and that they be exempted from the initial training requirements in proposed Paragraphs 10.1 through 10.3.**

To this end, we also recommend adding a definition of a certified thermographer as follows:

> ***Certified Thermographer*** **for the purposes of this Appendix, means a thermographer who has successfully completed the requirements for a Level 2 or higher thermography certificate compliant with ASNT-TC-1A or ISO 18436-7.**

B. Our members report confusion over the 12-month time (i.e., whether it is a calendar 12-months or a rolling 12-months) in the proposed senior OGI camera operator definition. **We recommend, as included in our recommended revised definition below, a sentence be added to the definition of senior OGI camera operator to clarify this point as follows "Previous 12-months means the 365-calender days prior to the day of the activity requiring a senior OGI camera operator."**

C. **Per the discussion in Comment I.4.B, we recommend the proposed definition of senior OGI camera operator be replaced. We suggest the following definition:**

> **A senior OGI camera operator is an OGI camera operator who has performed at least 100 hours of OGI monitoring (excluding their own initial and refresher training time) in the previous 12-months and has either 1) successfully completed the initial and field training specified in Section 10 of this Appendix and has completed any required refresher training or**

2) is a certified thermographer. Previous 12-months means the 365-calender days prior to the day of the activity requiring a senior OGI camera operator.

As discussed in comment II.1.C, “site” is an extremely unclear and imprecise term and we are suggesting that 100 hours of recent monitoring experience (i.e., in the previous 12 months) be specified instead. More critically, we are recommending removal of any “career” experience requirement. We do not believe career experience adds significantly to an operator’s ability to train or audit others. It is recent experience with current equipment and requirements at locations of the type currently being monitored that is critical to quality training and auditing, and we believe a 12-month criterion provides that expertise. Removing the proposed career criterion will increase the availability of senior OGI camera operators as OGI programs are being instituted and the demand for senior operators is at a maximum for training purposes and will make some senior operators available for actual monitoring duty.

One hundred hours of monitoring experience is consistent with the results of the operator experience testing reported in the Appendix K Technical Support Document (TSD)[6]. As shown in Table 4-35 (Overall Blind Survey Results for Leaks Released at 2% Concentration) and Appendix C-3 of the TSD, there was little difference among camera operators above the novice level (<10 hours of monitoring experience). In fact, the two most experienced operators (with >300 hours of field experience and >400 hours of laboratory experience) had the worst and the best results at finding leaks, respectively. The other operators did about equally well and had experience levels at or under 100 hours and some had no field monitoring experience at all. This conclusion is supported by others. In Appendix 1 to the Optical Gas Imaging Feasibility Study Summary Report included in the Appendix K TSD[7], it is reported that a Sage Environmental expert interviewed by EPA’s contractor stated, “that a trusted operator (one who has sufficient imaging experience to generate highly reliable results) has about 1 month or 100 hours of in-the-field use and experience.” Similarly, Texas has concluded that refresher training is not needed for an OGI camera operator with 100 hours in 12-months experience[8], an indication that that level of experience identifies a well-qualified individual.

The work of Zimmerle, et. al.[9] referenced in the TSD evaluated operator experience levels using test facilities typical of upstream equipment. They concluded that “Surveyors from operators/contractors who had surveyed more than 551 sites prior to testing detected 1.7 (1.5–1.8) times more leaks than surveyors who had completed fewer surveys” but they also point out their “data also indicate that all surveyors have a high probability of detecting large leaks” and thus “it is unclear if total emissions (which are generally dominated by large emitters) would be highly impacted.” While there is some variability, the data reported by Zimmerle, et. al. appears to show that their 551-site finding is equivalent to 200-250 hours of monitoring. We believe any operator meeting the >100 hour/12-month criterion we recommend would already have or quickly pass the 200-250 hours of experience and that

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[6] Docket Document EPA-HQ-OAR-2021-0317-0079, Eastern Research Group, Technical Support Document: Optical Gas Imaging Protocol, August 2, 2021, Pages 113 and 114

[7] Ibid.

[8] See 30 TAC 115.358(h)(2).

[9] Zimmerle, D., Vaughn, T., Bell, C., Bennett, K., Deshmukh, P., & Thoma, E. (2020). Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. Environmental Science & Technology, 54(18), 11506-11514. DOI: 10.1021/acs.est.0c01285

emission reduction effectiveness would not be seriously impacted in the interim because large leaks will be readily found by any camera operator.

Our recommended level of experience will assure the senior OGI camera operator duties are well performed and that their knowledge is current while expanding the pool of senior operators to assure an adequate supply and the availability of senior operators to perform monitoring as well as training and quality assurance functions.

It also should be clarified that monitoring hours performed by a senior operator as a quality check of another operator or as part of operator training counts toward the 12-month senior OGI operator monitoring criterion.

D. The proposed definition would seem to require that a senior OGI camera operator must have conducted OGI surveys at 500 different sites in their career and 20 different sites in the past 12 months. We recommend below this criterion be changed to a “hours in the previous 12-months” basis. None-the-less, many OGI camera operators, particularly those associated with a single company or facility, will not have access to many different sites or be able to monitor 100 hours at separate locations. Thus, as recommended in general in Comment II.1.E, **EPA should clarify that any field monitoring counts towards the senior operator’s site or hour’s criterion, whether at the same or separate locations, except for the senior operators own initial and refresher training hours.**

7. Paragraph 5.1 Site Hazards

The final sentence of this paragraph states, “It is the responsibility of the user of this protocol to establish appropriate health and safety practices and determine the applicability of regulatory limitations prior to implementing this protocol.” **This sentence is inappropriate and unnecessary and should be deleted.** Imposing health and safety requirements, even general ones such as this, is the responsibility of other Agencies.

Furthermore, it is the responsibility of all involved, not just the user of this Appendix to assure a safe and healthy operation. It is EPA’s responsibility not to incorporate unsafe requirements into this method. It is the responsibility of the site owner or operator to meet requirements applicable to the site and to establish other requirements it feels are needed. It is the responsibility of the OGI camera operator and his or her organization to meet regulatory and other requirements applicable to workers.

8. Section 6 Equipment and Supplies

A. **API supports the spectral range requirements in paragraph 6.1.1.** In refineries and other complex processes likely to eventually become subject to Appendix K, monitored components can contain many hydrocarbons with a range of individual response factors. It is important to making the OGI methodology feasible for these processes to balance the camera’s ability versus the range of components that may be in an emission and our limited ability to precisely characterize stream compositions. We believe the proposed paragraph accomplishes that balance and cameras meeting this specification will be widely applicable and will be able to identify emissions of these materials and thus assure equipment leak emissions are controlled. For upstream operations there is usually a dominant hydrocarbon in the streams being monitored and, therefore, the simpler, less burdensome requirement in §60.5397a(c)(7)(i)(A) is appropriate for those operations.

B. Paragraph 6.1.2 and its subparagraphs specify a minimum camera detection limit for methane and butane and various equipment to be used in demonstrating that those minimum limits are met. Requiring this test for every individual OGI camera is unnecessary since all cameras of a particular model are the same. Some camera configuration changes, as exemplified in the definition of camera configuration can impact detectability (e.g., changes sensitivity setting or camera lens) while other will not (e.g., whether camera is hand-held or mounted on a tripod). Thus, the detection limit demonstration is only needed for each configuration that could impact the detection limit. **We recommend that paragraph 6.1.2 be clarified to indicate that this testing may be performed by the equipment manufacturer for each model camera and for each configuration where a camera configuration parameter could impact the camera detection limit and that this demonstration does not have to be performed for every individual OGI camera.**

C. It is proposed in paragraph 6.1.2 to establish the minimum camera detection limit as detection of 17g/hr. methane and 18.5 g/hr. butane at specific distance, delta T and wind conditions. This is a change from the 60g/hr. (10,000 ppm methane/propane mix) minimum detection limit established in part 60 subpart OOOOa and that is in general use today. EPA explains in the proposal that 17g/hr. is what their current modelling shows is needed from bimonthly OGI to get the same emission reduction for methane as is achieved by subpart OOOOa Method 21 requirements[10]. It was shown previously that the subpart OOOOa OGI requirement is also equivalent to Method 21[11]. Thus, there does not seem to be any reason for changing the minimum detection limit demonstration (and possibly having to replace some cameras), requiring new operating envelope determinations, and potentially requiring changing procedures and permits that already use the OOOOa requirements. **API, therefore, recommends the minimum detection limit requirement from §60.5397a(c)(7)(i)(B)[12] be allowed as an alternative to the proposed paragraph 6.1.2 minimum detection limit and that the operating envelope determination procedure in paragraph 8.5 be revised accordingly.**

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[10] Op. Cit., page 63232

[11] Environ. (2004). Development of Emissions Factors and/or Correlation Equations for Gas Leak Detection, and the Development of an EPA Protocol for the Use of a Gas-imaging Device as an Alternative or Supplement to Current Leak Detection and Evaluation Methods. Final Report to the Texas Council on Environmental Technology and the Texas Commission on Environmental Quality.

[12] Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr. from a quarter inch diameter orifice.

D. To clarify the recordkeeping requirements associated with paragraphs 6.1.1 and 6.1.2 and to eliminate what could be viewed as a requirement for large volumes of unnecessary records, **we recommend that proposed second sentence of paragraph 8.1 be relocated to section 6 as 6.1.3 and that it require paragraph 6.1.2 records to be maintained by the organization doing the demonstration (usually the camera manufacturer)** and not by every site where that camera is being used. **We propose:**

> **6.1.3 Documents demonstrating compliance with paragraphs 6.1.1 and 6.1.2 must be retained with other OGI records by the owner or operator or testing organization, as applicable.**

E. Paragraph 6.2 specifies equipment needed to perform the minimum detection limit testing required by paragraph 6.1.2 and the operating envelopes required in Section 8. For clarity we recommend paragraph 6.2 be modified to be clear on where these requirements apply. **We recommend the following revised paragraph 6.2:**

> **6.2 The following items are needed for the initial performance verification of each OGI camera model configuration, as required by paragraph 6.1.2 and Section 8:**

F. Paragraph 6.2.4 calls for use of a mass flow controller or rotameter capable of controlling the methane and butane rates within a National Institute of Standards and Technology (NIST) traceable accuracy of 5% when testing a camera's detection limit or operating envelope. NIST traceability is not specified for any other instrumentation used in these demonstrations and seems unnecessary for this use. **We recommend the requirement for NIST traceability be removed.**

G. The paragraph 6.2.6 subparagraphs specify requirements for weather stations from which data will be used for the minimum detection limit testing required by paragraph 6.1.2 and the operating envelope testing in Section 8. It specifies the weather information be obtained from a weather station within 1 mile of test location and that the weather station instrumentation meets various listed specifications. In many cases, National Weather Service stations will be the basis for this data, and the testing facility will not have ready access to the instrumentation specifications at that weather station or the ability to influence that equipment. **We therefore recommend that weather data obtained from a National Weather Service Station located within 1 mile of the test location be allowed without requiring the information specified in paragraphs 6.2.6.1 through 6.2.6.5 to be collected.**

H. Paragraph 6.2.6.4 contains a typographical error. Wind direction is measures in degrees, not degrees Celsius as indicated in the draft.

9. Section 7 Camera Calibration and Maintenance

Our members report their experience with OGI cameras confirms that these cameras do not require any on-going calibration or routine maintenance. Thus, **we support Section 7 as proposed.**

10. Section 8 Initial Performance Verification and Development of the Operating Envelope

A. Paragraph 8.1 requires a record be maintained with other OGI records that each OGI camera meets the minimum detection limit requirements in paragraph 6.1.2. As indicated in Comment II.8.B, we anticipate it will be primarily the camera manufacturer's responsibility to assure the camera meets those specifications. Furthermore, many of these cameras will be used at multiple, separate facilities owned by different entities and it would be difficult and lead to a lack of cohesion for every entity that uses the camera and must maintain OGI monitoring records to have to maintain a copy of that documentation. **API therefore recommends this requirement be revised to require that the manufacturer of the OGI camera or other entity that performs the paragraph 6.1.2 evaluations be required to maintain the records showing compliance with the minimum detection limits and that such a record not be required to be kept by the camera owner or at each location where the camera is used. Further, we recommend this recordkeeping requirement be moved to paragraph 6.1, where it better fits (See Comment II.8.D).**

B. Operating Envelopes

a. As we discuss in Comment II.8.C, EPA's data shows equivalent performance is obtained by using the same methane/propane mix as used in part 60 subpart OOOOa for establishing camera minimum detection limits and operating windows as is obtained using methane and butane as proposed. Therefore, it is unnecessarily burdensome to require sources to change from a methane/propane mixture to methane and butane. **We therefore request that Appendix K allow use of either approach for setting operating envelope parameters (i.e., use methane/propane mix or use methane and butane)**.

b. As with the requirements in paragraph 6.1.2, in most cases establishing operating envelopes per the requirements of proposed paragraphs 8.2 through 8.6 can most efficiently, and with minimum methane and butane emissions, be developed by the manufacturer for each camera model configuration that could impact the camera's capabilities. Some camera configuration variations will not impact the camera capabilities and thus will not need a separate operating envelope. For instance, it usually makes no difference if a camera is hand-held, mounted on a tripod or mounted on a drone. If the mount is appropriately located to meet the maximum monitoring distance parameter of its operating window and is stationary (e.g., drone is hovering if a drone mount is in use) the same operating envelope is applicable. While there may be cases where a different operating envelope is needed for a unique monitoring situation, that will be the exception rather than the rule. In most cases, a single or a few operating envelopes will suffice for most monitoring. The key, which is addressed in Section 9 of the proposal, is assuring all equipment components being monitored are within an established operating envelope when they are monitored. **We, therefore, recommend that it be made clear in paragraph 8.3 that operating envelopes may be developed by the manufacturer or by others for each camera model and that separate operating envelopes are only required for camera configurations that impact the camera's ability to reliably locate leaks.**

c. **API also recommends paragraph 8.6 be revised to require that the entity that develops an operating envelope for an OGI camera model or configuration be required to maintain the records supporting that operating envelope and that not everyone that has to maintain OGI monitoring results must have those records, as the proposed paragraph 8.6 language would seem to require.** Since the users of an OGI camera need to know what operating envelopes are applicable, and the parameters for those operating envelopes**, we also recommend that the OGI camera owner or user maintain a record of the operating envelope parameters that apply for each configuration of their camera that they use.** Again, this needs to be the camera users or owners' responsibility, since many of these cameras will be used at multiple locations owned or operated by many different entities and the camera owner may not even be a facility owner or operator (e.g., a monitoring contractor).

d. Finally, it would be a clarification if the wording of paragraphs 8.3 through 8.6 be revised to indicate there may be multiple operating envelopes for a particular camera configuration. **We suggest a few specific wording revisions in the Appendix K redline included in this submission**.

11. Section 9 Conducting the Monitoring Survey

A. General

a. Throughout Section 9 of the proposal the monitoring plan requirements are stated as requirements for each site. However, much of the information is not site specific (e.g., procedure for assuring operating envelope conditions are met, procedures for documenting monitoring surveys). Most of those procedures are generic for a particular camera and monitoring approach and apply to many sites, often sites with different owners. Many of the procedures in a monitoring plan will be the responsibility of the camera owner or contract monitoring firm. There is no justification for forcing every site to develop those procedures or even to have a record of the generic ones. Rather than trying to list who should be responsible for each procedure **we recommend these requirements (except for paragraph 9.7) be reworded to simply identify monitoring plan content requirements without specifying who is responsible for them.** We make specific recommendations as to maintenance of the monitoring plan records in the next comment and in our recordkeeping comments in Section 17 of these comments.

b. Section 9 of the proposal requires that each site have a monitoring plan that describes the procedures for conducting a monitoring survey. Proposed paragraph 12.2 requires the facility must maintain a record of the site monitoring plan. We comment on the specifics of recordkeeping paragraph 12.2 in Comment II.17.B, however, we believe that both the section 9 and paragraph 12.2 need to be clarified that it is not required that a copy of the plan be maintained at every site. Typically, such a plan would be developed centrally and would be available electronically as needed by the camera operators when they are monitoring that site. **We suggest the introductory sentence to section 9.0 be revised to the following.** We recommend an equivalent change in our recommended changes to paragraph 12.2.

> **9.0 A monitoring plan that describes the procedures for conducting a monitoring survey at each site must be readily available to the camera operator.**

B. **API generally supports the proposed daily initial verification checks in paragraph 9.1.** In our experience these checks assure the OGI camera is functioning properly. However, we see no value in the burden imposed by paragraph 9.1.4 that requires a video record of the camera imaging a butane lighter or other validation source. It is more than adequate to simply have confirmed that the camera sees the butane lighter image as part of confirming the entire 9.1 set of requirements were met. It is overly burdensome and unnecessary to require daily video records of that determination. Storing thousands of videos, no matter how short, is difficult and there needs to be a significant justification for any such a requirement. **API recommends paragraph 9.1.4 be deleted.**

C. Paragraph 9.3 requires a monitoring plan for each site to identify monitoring survey methodologies that ensure all regulated components are monitored. It provides only three approaches that may be used. All three approaches are extremely complex, and the burdens imposed are often not justified versus other alternatives. We comment on some of the specifics of the three approaches next (in Comment II.11.D.b), though we believe paragraph 9.3 should be replaced in its entirety.

As was found for Part 60 Subpart OOOOa sources (as described below), we believe other approaches to those proposed for assuring all components are included are available or will be identified as thousands of monitoring programs are developed and executed and as technology improves. Use of such alternatives should be encouraged where they prove more efficient**.**

Limiting survey monitoring methodologies to only three is also inconsistent with the stated intent of the current proposal[13]. On page 63165 of the current proposal, EPA states:

> The 2016 NSPS OOOOa, as originally promulgated, required that each fugitive emissions monitoring plan include a site map and a defined observation path to ensure that the OGI operator visualizes all of the components that must be monitored during each survey. The 2020 Technical Rule amended this requirement to allow the company to specify procedures that would meet this same goal of ensuring every component is monitored during each survey. While the site map and observation path are one way to achieve this, other options can also ensure monitoring, such as an inventory or narrative of the location of each fugitive emissions component. The EPA stated in the 2020 Technical Rule that ‘‘these company-defined procedures are consistent with other requirements for procedures in the monitoring plan, such as the requirement for procedures for determining the maximum viewing distance and maintaining this viewing distance during a survey.’’ 85 FR 57416 (September 15, 2020). Because the same monitoring device is used to monitor both methane and VOC emissions, the same company-defined procedures for ensuring each component is monitored are appropriate. Therefore, <u>the EPA is proposing to similarly amend the monitoring plan requirements for methane and for compressor stations to allow company procedures in lieu of a sitemap and an observation path.</u> [Underline emphasis added.]

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[13] Ibid.

For these reasons, **we request language based on Part 60 Subpart OOOOa §60.5397a(d)(1)[14] be substituted for the proposed paragraph 9.3. That language we recommend is as follows:**

> **Your plan must include procedures to ensure that all equipment leak components are monitored. Example procedures include, but are not limited to, a sitemap with an observation path or GPS coordinates, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.**

D. Should the proposed paragraph 9.3 not be replaced with the language from Part 60 Subpart OOOOa or an equivalent, we have the following comments on the proposed paragraph 9.3 language.

a. The proposed three approaches are clearly intended for use at larger operations where many monitoring locations are needed and there is a large infrastructure and significant resources to allow marking monitoring locations, mapping routes and maintaining this information. Many locations subject to the current rulemaking are smaller facilities or portions of a facility (e.g., a flow meter station or a tankfield pump station) where monitoring will require one pair of observations (two views of the components) or at the most a few observations. It is unnecessary and overly burdensome to have to manage repetitive route maps, to place and maintain monitoring location markers or even identify GPS coordinates in such situations. Thus, if section 9.3 is not replaced, **we recommend an additional option be added that would apply to facilities where less than 25 monitoring observations are needed to monitor all components regulated by a referencing subpart or permit.** The term "monitoring observation" refers to each pair of camera locations[15] used to visualize a particular collection of equipment leak components (e.g., a piping manifold, a meter station). Under that option, the monitoring plan would allow for a description of the approach that will be used (e.g., monitor all components from two views at least 90 degrees apart) and a list of the facilities or facility locations to which this option applies.

b. For the reasons discussed in Comment II.1.C, **we recommend the word "site" in paragraph 9.3 (if maintained) be removed. We suggest the paragraph start with "Conduct monitoring using …"**

c. **We also recommend the wording of paragraph 9.3 sentence two, if maintained, be clarified to indicate that a mix of the options is allowed if all components subject to OGI monitoring under the referencing subpart or permit are monitored.** As proposed, that sentence requires the use of the same option for an entire facility. For larger facilities and facilities with a mix of densely located components and remote collections of components, use of a mix of the options may be most efficient.

d. **In paragraph 9.3 (if maintained), we also recommend the last sentence be clarified to indicate that a component database is not required.**

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[14] §60.5397a(d)(1) states, "(1) If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components."

[15] Typically, at least two different views of potential leak sources are used for OGI monitoring.

e. Given the massive number of route maps, GPS coordinates and site lists that must be recorded and maintained if this provision is not replaced, **it is critical that it be clarified that this information may be in electronic form (e.g., databases, spreadsheets) and not "included as part of the monitoring plan" as apparently required by the draft language.**

E. Paragraph 9.4 and Table 14-1 specify minimum dwell times for observations.

a. **API requests EPA explain the basis for the dwell time requirements in the formal proposal of Appendix K (i.e., the Table 14-1 entries)**, so we can provide scientifically valid comments.

b. API believes that setting prescriptive dwell times is unnecessary and introduces inefficiencies and wasteful burdens. An experienced camera operator will determine dwell time based on the circumstances – some views may require an extended dwell time and other views may need shorter dwell time. **Dwell time should be an element of operator training and auditing, but not specified in Appendix K.** Dwell time is already included in paragraph 10.2.1.5 training requirements, in monitoring plan requirements and dwell time issues would become readily apparent in the final field training test and during performance audits and other quality control activities as required by paragraph 11.1. In the work of Zimmerle[16], et. al. dwell times were not identified on a per component basis. However, they did report the range of times operators took to complete surveys of three different typical upstream installations, where leaks were artificially introduced. They reported the range of monitoring times as follows.

Test Site	Monitoring Time (min)
1	3-52 (mean 19)
2	1-89 (mean 18)
3	9-108 (mean 39)

With that wide range of monitoring times, it is impossible to identify minimum dwell times that do not introduce inefficiency. Unnecessarily long dwell times result in inefficient emission reductions and take time and resources away from other compliance activities with greater environmental benefits. Zimmerle's work clearly identifies that experienced operators adjust the dwell time of an individual observation to account for environmental considerations (e.g., background) and for the type of equipment and process conditions and the likelihood of leaks. It is the ability to make these adjustments that makes the monitoring process efficient. If dwell times are not flexible, efficiency is lost, since extended time is spent looking at the many components that are not leaking or even likely to leak. Zimmerle also reported that while the number of smaller leaks identified increased with increased monitoring times, identification of larger leaks was not significantly impacted, so the mass of emissions identified was not overly sensitive to the monitoring time.

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[16] Ibid.

Specifying a dwell time discourages a camera operator from adjusting for prevailing conditions. Once the specified dwell time is reached there is no reason for an operator to spend additional time, even if the situation requires it.

F. Paragraph 9.5 requires that the monitoring plan address camera operator fatigue. It includes specific requirements to address this concern. Imposing specific ergonomic requirements such as proposed in this paragraph is outside the scope of an EPA method. Furthermore, the approach must be tailored to the situation. For instance, under this rulemaking most monitoring will be in short bursts with travel time between monitoring locations. Nothing specific is needed in these situations to prevent operator fatigue. In more densely populated situations relief may be needed, but the times for breaks need to be matched to the situation. For instance, arbitrarily requiring a break 5 minutes before lunch or quitting time makes no sense. Similarly, stopping a monitoring round that takes 23 minutes to complete for a break at twenty minutes (as specified in the proposal) is equally nonsensical. Additionally, 20 minutes may be too long between breaks in some situations. For instance, if the camera operator had to climb a hundred-foot tower to perform monitoring or monitor in particularly hot situations.

We do not believe there is a generic approach that would not significantly interfere with the efficient execution of this program and **we, therefore, recommend that all but the first sentence of proposed paragraph 9.5 be deleted**.

G. Paragraph 9.6 requirements apply to a “monitoring survey,” but that is an undefined and ambiguous term and the requirements do not really fit since, depending on the situation, single site or even a single process unit can take anywhere from less than an hour to many days to complete. Furthermore, we see no value for requiring weather data when monitoring moves from one process unit to another at the same location or at the end of the day. Even where there are large process units, weather does not change significantly because of location changes within a facility and end of day weather information is of no use in assuring operating envelope requirements are being met, since monitoring has concluded for the day.

We suggest paragraphs 9.6.1 and 9.6.2 be replaced with the following to address this variability

> **9.6.1 For each monitoring day or change in facility, record the date, approximate start and stop times and the name of facility where the monitoring is performed.**
>
> **9.6.2 At the start of each monitoring day or a change in facility, record the weather conditions, including ambient temperature, wind speed, relative humidity,and sky conditions.**

H. Leaks

a. Paragraph 9.7 specifies documentation requirements for leaks found (video clip) and clarifies that no video record is required unless a leak is found. **API strongly supports the important clarification that individual records are not required unless a leak is identified.** Obtaining and maintaining video records is a major burden and is only justified where there is a reason, such as where a leak has been identified and a video clip or digital picture will aid in identifying the location of the leak for repair personnel.

b. Paragraph 9.7.1 requires that if a leak is identified, a video clip be taken, and the leak tagged for repair. The final sentence of the paragraph suggests the video clip is needed to allow the operator to find the leak. Since it is required that the leak be tagged, it does not seem there would be a need for a video or even a still picture to help find the leak. As indicated in the subpart OOOOa quote below, that subpart only requires tagging or an image, not both. No justification for requiring both is provided in the record.

Furthermore, there are situations where immediate repair or tagging of a leak can impose a potential safety problem and thus the absolute requirement to tag all leaks is infeasible. Safety issues occur, for instance, if the leak is in an extremely hot piece of equipment (e.g., in a furnace process outlet line), where there is no immediate safe access available (e.g., in a pipe rack, on the side of a tower), or where toxics such as hydrogen sulfide is or may be present. In these cases, a video or a digital picture could be helpful in identifying the leak location and the burdens associated with requiring such a record are justified. As we have previously discussed, any video record requirement adds burden and can be difficult to reliably meet. A digital picture, as opposed to a video, has the advantage of being much easier to store and can better show reference points that help identify the leak location when compared to video. Paragraph 60.5397a(h)(4)(ii) of part 60 subpart OOOOa requires a digital picture of leaks that are not immediately repaired or tagged, and that approach has been in successful use since September of 2015. Paragraph 60.5397a(h)(4)(ii) states:

> For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component, or the component must be tagged during the monitoring survey when the fugitives were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

Thus, **we request that paragraph 9.7.1 be revised to parallel the part 60 subpart OOOOa approach, allowing either a video or a digital picture and only imposing that requirement where a leak is not immediately repaired or tagged and that only a written record of the leak information be required otherwise.**

I. Paragraph 9.7.3 requires a 5-minute per day quality assurance video for each camera operator. The paragraph specifies that the video must document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration. It is unclear how such a video clip would show compliance with that list of items. For instance, dwell times, angles, distances, backgrounds will vary for every monitoring occurrence, since they depend on the equipment being monitored, the location of the camera relative to the component locations, the background and the weather. A video does not show whether those parameters are being met. A video does not show whether all operating envelope criteria are being met, even for the situation being viewed. Furthermore, video of camera operators who know they are being videoed is unlikely to be representative. The required quarterly (or as we recommend annual) performance audits, proper training, the daily equipment startup checks and the quality assurance requirements in paragraph 11.1 provide all the appropriate quality assurance much more effectively and efficiently than this proposed video requirement. Furthermore, creating extensive video records that are difficult to reliably store, provide no useful information, and are unlikely to ever be reviewed, imposes a large and overly burdensome mandate.

We are also concerned that EPA underestimates the burden of storing video files, specifically storing the 5-minute per camera operator per day videos required in paragraph 9.7.3. There are actual examples of data storage issues associated with the requirement in MACT CC (63.670(h)(2)), which requires recordkeeping of photos taken of a flare every 15 seconds (or 2,102,400 images per year per flare). For at least one of our member companies operating several refineries, the flare images are *not* stored on the Cloud. Rather, they are saved locally on a server for several reasons, primarily for security. Refineries often have very tight Information Technology (IT) security systems because of the nature of the industry. Additionally, some member companies have experienced a loss of some of the photos because of power outages or other technical issues associated with handling the sheer volume of images. The flare images add up quickly, and the videos required by paragraph 9.7.3 will as well. For comparison, a high-definition video is 60 frames per second. Assuming 5 such videos per day for 250 days per year for a refinery then represents 22,000,000 images. The burden of saving these videos on the slight chance someone may want to review one is not justified, since, as discussed above, we do not see them providing any compliance assurance value.

Paragraph 9.7.3 and the corresponding entry in the table in paragraph 11.3 should be deleted.

12. Paragraph 10.2 Initial OGI Camera Operator Training

Paragraph 10.2.1 addresses initial "classroom" training of OGI camera operator trainees. As discussed in Comment II.1.F, it needs to be clarified throughout Appendix K that this can be computer-based training and does not have to be in-person classroom training.

Paragraph 10.2.2 addresses the required field training. It calls for a minimum of 1) 10 site surveys where the trainee is observing a senior OGI operator, 2) 40 site surveys where monitoring is performed side-by-side with a senior OGI operator, 3) 50 site surveys where a senior OGI operator observes the trainee performing monitoring and 4) a final survey where a senior OGI operator performs a follow-up survey that demonstrates the trainee did not miss any persistent leaks. There are many issues with these requirements as follows.

A. Paragraph 10.1 calls for a training plan. It includes a sentence saying, "If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement." **API recommends this sentence be deleted.** Any company contracting for OGI monitoring services has a responsibility to assure that those services meet any applicable requirements. There is no reason a training plan is any more critical than any of the other requirements of Appendix K. Nor is it clear how individual facilities would "ensure" compliance with the training plan requirements or why each facility would have that responsibility if the monitoring contract involved many facilities. Imposing an unclear burden on every facility that does OGI monitoring using Appendix K aggregates to a large and unnecessary burden.

B. As discussed in Comment II.1.C, site is an imprecise term and could require monitoring for minutes at a location with only a few potential leak components or could require monitoring for months at a location with hundreds of thousands of potential leak components. Thus, **we recommend the word "site" be deleted from these paragraphs and these training requirements should be based on monitoring hours as discussed below.**

C. If we assume a reasonable training OGI survey as roughly 20 minutes of monitoring (EPA's suggested monitoring duration without a break in proposed paragraph 9.5), the proposal will require over 34 hours of actual field monitoring training for the trainee and over 17 hours of one-on-one senior OGI operator monitoring time, assuming as discussed below the required observational items can be done in groups. Obviously, much more time would be required if "survey" is left undefined and thus involved more than 20 minutes of monitoring. Considering set-up, breaks, lunch, equipment relocation, etc. this will require well over a week of trainee time and half a week of senior operator time (per trainee).

In our experience, 34 hours of field monitoring training is unnecessary to assure well-trained operators. In fact, Texas has concluded only 24 hours of total initial training is necessary[17]. Based on that experience, the need to train large numbers of OGI camera operators initially and the likely shortage of senior OGI camera operators, **we recommend 1) field monitoring training be limited as discussed below, 2) field monitoring training require monitoring surveys of approximately 20-minutes each and 3) that it be clarified that the observational portions of the training do not have to be one-on-one**. We amplify on these recommendations in the following comments (II.12.D and E). In combination with the initial classroom or computer-based training, these recommendations would provide more than the 24-hour minimum required by Texas.

D. Paragraph 10.2.2 requires 10 surveys where the trainee observes a senior operator, 40 surveys side-by-side with a senior OGI operator and 50 surveys with a senior operator overseeing the trainee. In our experience, this is excessive, particularly the amount of side-by-side surveying. Nor as discussed below and elsewhere, will there be enough senior OGI operators to perform these functions if the requirements for reaching senior operator status are unchanged. We believe side-by-side monitoring can be done with operators meeting our suggested revised senior OGI camera operator definition with no loss in quality versus senior operators meeting the proposed definition. It is also important that the

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[17] §115.358(h)(1) of Title 30 of the Texas Administrative Code requires "Operator training. Any person that performs the alternative work practice in this section shall comply with the following minimum training requirements.

(1) The operator of the optical gas imaging instrument shall receive a minimum of 24 hours of initial training on the specific make and model of optical gas imaging instrument before using the instrument for the purposes of the alternative work practice.

revised language be clear that the observational training does not have to be one-to-one (see our suggestions in the Appendix K redline attached to these comments). Thus, **we recommend these requirements be revised to 10 20-minute monitoring surveys where a group of trainees observes a senior OGI camera operator, 50 20-minute monitoring surveys where a senior operator oversees a group of trainees and 5 20-minute monitoring surveys side-by-side with a qualified operator.** The proposed final survey test in proposed paragraph 10.2.2.4 (modified as discussed below) would complete the training. This would provide a total of approximately 23 hours of field experience for each trainee prior to their starting to perform monitoring surveys.

E. Final Field Training Test

a. Paragraph 10.2.2.4 requires a final monitoring test where the trainee conducts an OGI survey, and a senior OGI camera operator follows behind with a second camera to confirm the trainee's survey results. Consistent with our recommendation for performance audits below, **we recommend this final test be of 1-hour duration (e.g., 3 20-minute periods) to assure a sizable number of components are monitored.**

b. The criterion for passing this final test is "The trainee must achieve zero missed persistent leaks relative to the senior OGI camera operator …" We believe the criterion of zero missed persistent leaks is unreasonable and should be revised. First, even if the follow-up survey is performed immediately after the trainee's survey, there can be changes in leak rates, interferences, etc. that occur and can cause a marginal leak to be observed in one survey and not the other. Second, a leak may occur continually through a dwell period and still not occur at another time. Thus, it is quite possible in the real world that a leak can be observed in one survey and not occur in another survey even if the other survey is just a few minutes earlier or later. These differences can occur for either survey. In the real world, it is just as likely the trainee will observe "persistent" leaks that the qualified operator does not. EPA has acknowledged this potential issue for marginal leaks even in carefully controlled situations by establishing a 75% criterion (3 out of 4) when establishing operating envelopes for an OGI camera.[18] As proposed, paragraph 10.2.2.4 also presumes the senior operator monitoring always observes more leaks than the trainee observes. That is unreasonable and the passing criteria must allow for either situation. For these reasons, **we recommend that the criterion for passing the final test be changed to at least 90% agreement or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

c. Paragraph 10.2 is silent as to what is required if an OGI operator trainee fails the final test required by paragraph 10.2.2.4. **API recommends that if 90% agreement is not achieved, the senior operator should work with the trainee on the reasons for the failure and then the test should be repeated.** In the case of a second failure, the trainee should be required to go through the refresher level of training prescribed in paragraph 10.3 before retaking thew final test. A one and done failure construct creates arbitrary barriers to developing a qualified workforce.

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[18] See paragraph 8.5.3 of the proposal.

13. Paragraph 10.3 Refresher training

A. Paragraph 10.3 requires annual refresher training for OGI operators. In our experience annual refresher training is unnecessary considering the ongoing quality assurance requirements, and the typical amount of oversight that occurs. Even in the TSD, it is recognized that refresher training is not always needed. For instance, it is stated on page 115 that "If OGI technicians are regularly sent out to the field to perform surveys, then re-validating their performance may not be necessary, but could also be as simple as having a superior repeat a survey and report on the established technician's performance." **We recommend the refresher training be on a three-year interval.**

B. There are many OGI monitoring programs already underway and thus there are some experienced camera operators already in place. It would be unnecessarily burdensome for them to have to go through the entire initial training program when they first must meet Appendix K requirements. They would only need to understand the specific requirements of this Appendix. Thus, **we recommend that an OGI camera operator with at least 24 hours of OGI monitoring experience in the previous 12 months, but no previous Appendix K experience, only be required to go through the refresher level of training rather than the full initial training and then pass the field training final test in paragraph 10.2.2.4.**

14. Paragraph 10.4 Performance Audits

A. Paragraph 10.4 requires quarterly performance audits. Our experience suggests that formal quarterly audits of camera operators are excessive. We note that other similar work practice programs, such as the Method 21 LDAR monitoring program has been successfully in service for more than 40 years without a similar audit requirement. Considering the requirements for an on-going quality control program in proposed paragraph 11.1, annual performance audits are certainly adequate. **We recommend changing this requirement to annual audits**.

Besides reducing burdens and freeing camera operators for actual monitoring activities, this change in audit frequency has the added benefit of reducing the demand on senior OGI camera operator time, thereby allowing more time for senior operators to do monitoring and training.

B. Since senior OGI camera operators will carry out any required performance audits, they will automatically frequently review monitoring requirements and have an opportunity to identify and correct any issues of their own. Such issues would be apparent as they compare results if a comparative monitoring option is used and when reviewing, either in person or via video the auditee. Thus, **API recommends senior OGI camera operators not be required to undergo performance audits.**

C. Paragraph 10.4.1 outlines a performance audit option using comparative monitoring and paragraph 10.4.2 outlines a performance audit option using video review. We comment on the specifics of those approaches in our next comment (Comment II.14.D). We support providing alternative audit approaches, since there will be many variants in monitoring organizations, monitoring schedules, senior OGI camera operator availability, and facilities, but believe there are more than two alternatives to evaluating the performance of a camera operator. Therefore, **we recommend that the performance audit methodologies that will be used be required to be included in the monitoring plan as already implied in proposed paragraph 11.1 and that the approaches in paragraphs 10.4.1 and 10.4.2 only be cited as examples.**

Alternative approaches include visual observation by a senior OGI camera operator (as opposed to their reviewing a video) or observation by a monitoring supervisor or review of results from monitoring at a test facility, among others.

D. Performance Audit Procedures

a. Paragraphs 10.4.1.1 and 10.4.2.1 require audits of at least 4-hours with no persistent leaks identified by the auditor that were missed by the auditee. Four hours is an excessively lengthy period and is not needed to assess if an auditee is monitoring correctly. One-hour is more than adequate to determine if the auditee is following procedures and can identify leaks. Nor is a 4-hour requirement it a reasonable use of resources, tying up an OGI camera operator and an auditor for more than a day per audit (4-hours for the trainee monitoring and 4 hours for the follow-up senior OGI operator survey) and for video audits a third person (taking the video) for half a day. **We recommend the 4-hour requirement be changed to require audits of 1-hour total duration (i.e., 3 20-minute periods) and, as discussed in Comment II.14.A, these audits only be required annually.**

b. Paragraph 10.4.2 provides a performance audit procedure wherein a senior OGI camera operator observes the auditee by reviewing a video of that auditee performing monitoring. While that approach is useful where senior operators are not readily available, in many cases it would be easier for the senior operator to simply observe the auditee by following them around. This also eliminates the issues associated with needing an additional (i.e., third) person to take the video and of storing the video. **Thus, if this requirement is maintained, we recommend it also allow for a senior operator to simply observe the auditee and not have to record a video.**

c. For all the reasons presented in Comment II.12.E.b, **we also recommend that the criterion for passing the audit be changed to at least 90% agreement of the number of persistent leaks found or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

d. **We also request EPA make clear that these audits may be performed by the OGI camera operator employer or a site owner or operator and there is no requirement for additional audits as the camera operator moves from one site to another or from employer to employer.**

e. There is a typographical error in that paragraph 10.4.2.2 is labelled as 10.4.2.3 in the draft Appendix K.

f. Paragraphs 10.4.1.2 and 10.4.2.2 specify retraining requirements for an operator that fails the audit criterion. The retraining requires a minimum of 1) 10 site surveys where the trainee is observing a senior OGI operator, 2) 5 site surveys where monitoring is performed side-by-side with a senior OGI operator, 3) 10 site surveys where a senior OGI observes the monitoring and 4) a final survey where a senior OGI operator performs a follow-up survey that demonstrates the operator in training did not miss any persistent leaks. First, as discussed in Comment II.1.C **we recommend the word "site" be deleted**

from these paragraphs and the monitoring requirements be expressed on a time basis. Second, we believe the retraining proposed is excessive and overly burdensome. Failures to observe a leak or to follow some aspects of the monitoring procedure are situation specific. General retraining dilutes the focus on the real problem(s) and uses up precious monitoring time and senior resources on issues that are not a problem. Therefore, we believe it is impossible to specify a retraining paradigm that is generic and resource efficient. Rather, **we believe the requirement should be to specify that retraining is required to address monitoring aspects observed to be an issue during the audit and that the auditee must then pass a new comparative audit by achieving at least 90% agreement on the number of persistent leaks or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

15. Paragraph 10.5 Returning Operators

A. This paragraph states, "If an OGI camera operator has not conducted a monitoring survey in over 12 months, then they must repeat the initial training requirements in Section 10.2." This is excessive for an experienced operator who has, for example, been temporarily in another job or out due to an extended sickness. Rather, **we recommend the returning operator be only required to take refresher training and to pass a performance audit. Furthermore, for clarity, we recommend this requirement be integrated into paragraph 10.3 on refresher training.**

16. Section 11 Quality Assurance and Quality Control

A. Consistent with our recommendation in Comment II.11.J to delete Paragraph 9.7.3, **the second sentence of paragraph 11.2 should be deleted.**

B. We have commented individually on the QA/QC requirements proposed throughout. **Paragraph 11.3 summarizes those requirements and will need to be updated to match the final version of the Appendix.** We have included recommended revisions in the redline version of Appendix K that we are submitting with these comments.

Additionally, some of the wording in the frequency column of that table is unclear as to who is responsible and how often and on what basis the QA/QC activity is required. We have suggested improved wording and addition of specific references to the paragraph containing the requirement in the redline version of Appendix K that we are submitting with these comments.

17. Section 12 Recordkeeping

A. As indicated in the following specific comments, "facility" is the wrong basis for requiring most records. Many of the required records will be developed by the camera manufacturer. Others should be housed in owning or operating company central repositories because it is more efficient and because some sites potentially subject to these requirements are not continuously staffed and have no onsite recordkeeping facilities. Training and other operator records should be handled by the camera operator's employer, often not the owner/operator of any facility being monitored. Nor would it be manageable or sensible to require copies of these various records to be made for each of the facilities that will be subject to monitoring. **Thus, as suggested more specifically below, we recommend the word "facility" be deleted from this section and the appropriate entity (e.g., camera owner, facility owner or operator, camera operator employer) be substituted or no specific entity be identified as having to maintain the record.** Consistent with this change, **the general recordkeeping requirement in paragraph 12.1 should be generalized to "Records required by this Appendix must be kept for a period of five years, unless otherwise specified in an applicable subpart."**

B. Paragraph 12.2 says, "The facility must maintain the following records in a manner that is easily accessible to all OGI camera operators:" However, except for paragraph 12.2.1 (the site monitoring plan) and 12.2.4 (operating envelope limits) the other listed records are associated with the camera, and many cameras will be used at multiple facilities and may not be owned by the facility or even the facility owner. In fact, it can be anticipated that many cameras will be owned by a monitoring company. Even in the case of the site monitoring plan, as we discussed in Comment II.11.A, much of the content of that plan will be the responsibility of the camera owner. While a facility owner or operator will have significant input relative to monitoring routes and safety issues, the camera owner or monitoring contractor is the appropriate owner of this plan it would be their responsibility to see that their camera operators have ready access to the plan, not the responsibility of the facility owner unless the monitoring personnel are in-house. **Thus, "facility" should be deleted from the paragraph 12.2 wording, and it should be rephrased to say, "The following records must be maintained, as applicable" and a sentence added to require that operating envelope limits and applicable site monitoring plans be readily accessible to camera operator.**

C. Paragraphs 12.3 requires records of data supporting development of the operating envelope. We anticipate most, though not all, operating envelope development will be done by the camera manufacturer and thus **paragraph 12.3 should require operating envelope supporting data to be maintained by the developer of the operating envelope.**

D. Paragraph 12.4 contains requirements applicable to camera operators. These records are the purview of the operator's employer and not , in most cases, individual facilities or even operating companies. **Paragraph 12.4 should be clarified to require these records to be maintained by the camera operator's employer or facility owner or operator as applicable.**

E. Paragraph 12.4.3 appears to require records of operator training activities, but starts by requiring "The number and date of all surveys performed …" Records of actual monitoring surveys need to be maintained by the owner or operator of the site monitored and are covered by paragraph 12.5. Thus, this introductory phrase in paragraph 12.4.3 needs to be limited to surveys associated with training. If some of those training surveys are performed to locate leaks, records will need to be maintained with the training records required by paragraph 12.4.3 and, also, with monitoring records as required by paragraph 12.5. **We therefore recommend the introductory phase in paragraph 12.4.3 be revised to "The number and date of all training surveys performed …"**

F. Paragraph 12.5 deals with monitoring records and requires that the listed records be available to the technicians' executing repairs. Yet, most items are not associated with repairs or locating the leak and it is overly burdensome to require that they be made available, particularly if the monitoring is not being performed by an employee of the site being monitored. **Therefore, we recommend only proposed paragraph 12.5.6 be required to be available to the repair technicians**.

Attachment B

Suggested Redlines to Prepublication Draft Appendix K

Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging

[API recommended changes shown in redline mode]

1.0 Scope and Application

1.1 Analytes.

Analytes	CAS No.
Volatile Organic Compounds (VOCs)	No CAS number assigned.
Methane	74-82-8
Ethane	74-84-0

1.1.1 This protocol is applicable to the detection of VOCs, including hazardous air pollutants (HAPs),and hydrocarbons, such as methane and ethane.

1.2 Scope. This protocol covers surveys of process equipment using Optical Gas Imaging (OGI) cameras in oil and gas upstream and downstream sectors (from production to refining to distribution). Thespecific component focus for the surveys is determined by the applicable subpart, and can include, but is not limited to, valves, flanges, connectors, pumps, compressors, open-ended lines, pressure relief devices,and seal systems.

1.3 Applicability. This protocol is applicable to equipment leak components at facilities ~~all facility types from the upstream and downstream oil and gas sectors and may apply to well heads, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities~~ when referenced by an applicable subpart. ~~This protocol is not applicable to chemical plants or other facility types outside of the oil and gasupstream and downstream sectors.~~ This protocol is intended to help determine the presence and location of leaks and is not currently applicable for use in direct emission rate measurements from sources.

2.0 Summary

2.1 A ~~hand-held,~~ field portable infrared (IR) camera capable of imaging the target gas species is employed to survey process equipment and locate fugitive or leaking gas emissions. By restricting the amount of incoming thermal radiation to a small bandwidth corresponding to a region of interaction for the gas species of interest, the camera provides an image of an invisible gas to the camera operator. The camera type and manufacturer are not stated in this protocol, but the camera used must meet the specifications and performance criteria presented in Section 6. The keys to becoming proficient and maintaining leak detection proficiency using OGI cameras are proper camera operator training with sufficient field experience and conducting OGI surveys frequently throughout the year.

3.0 Definitions

Ambient air temperature means the air temperature in the general location where the OGI survey isbeing performed.

Applicable subpart means a subpart in 40 CFR part 60, 61, 63, or 65 that requires the monitoring of regulated equipment for fugitive emissions or leaks, for which this protocol is referenced.

Camera Configuration means different ways of setting up an OGI camera that affect the detection capability. Examples of camera configurations that can be changed include the operating mode (*e.g.,* standard versus high sensitivity or enhanced), the lens, the portability (*e.g.,* handheld versus tripod or drone mounted), and the viewer (*e.g.,* OGI camera screen versus an external device like a tablet).

Certified Thermographer, for the purposes of this Appendix, means a thermographer who has successfully completed the requirements for a Level 2 or higher thermography certificate compliant with ASNT-TC-1A or ISO 18436-7.

Delta temperature (delta-T or ΔT) means the difference in temperature between the emitted process gas temperature and the surrounding background temperature. It is an acceptable practice in the field to assume that the emitted process gas temperature is equal to the ambient air temperature.

Dwell time means the time required to survey a manageable subsection of a scene in order to provide adequate probability of leak detection. The dwell time is the active time the operator is looking for potential leaks and does not begin until the scene is in focus and steady.

Fugitive emission or leak means any emissions observed using ~~OGI~~optical gas imaging from any equipment component identified in the referencing subpart or permit as being subject to monitoring using this Appendix (Appendix K).

Imaging is the process of producing a visual representation of emissions that may otherwise be invisible to the naked eye.

Operating envelope means the range of conditions (*i.e.,* wind speed, delta-T, viewing distance) within which a survey must be conducted to achieve the quality objective.

Optical gas imaging camera means any ~~hand-held,~~ field portable instrumentation that makes visible emissions that may otherwise be invisible to the naked eye.

Persistent leak is any leak that is not intermittent in nature.

~~*Repair* means that a component is adjusted, or otherwise altered, to eliminate a leak.~~

Response factor means the OGI camera's response to a compound of interest relative to a reference compound at a concentration path-length of 10,000 part per million-meter. ~~Response factors can be obtained from peer reviewed articles or may be developed according to procedures approved by the Administrator.~~

Senior OGI camera operator is a camera operator who has performed at least 100 hours of OGI monitoring (excluding their own initial and refresher training time) in the previous 12-months and has either 1) successfully completed the initial and field training specified in Section 10 of this Appendix and has completed any required refresher training or 2) is a certified thermographer. ~~has conducted OGI surveys at a minimum of500 sites over the entirety of their career, including at least 20 sites in the past 12 months, and has completed or developed the classroom camera operator training as defined in Section 10.2.1.~~ Previous 12-months means the 365-calender days prior to the day of the activity that requires a senior OGI camera operator.

4.0 Interferences

4.1 Interferences from atmospheric conditions can impact the operator's ability to detect gas leaks. Itis recommended that conditions involving steam, fog, mist, rain, solar glint, high particulate matter concentrations, and extremely hot backgrounds are avoided for a survey of acceptable quality.

5.0 Safety

5.1 Site Hazards. Prior to applying this protocol in the field, the potential hazards at the survey site should be considered; advance coordination with the site is critical to understand the conditions and applicable safety policies. This protocol does not address all of the safety concerns associated with its use. ~~It is the responsibility~~

~~of the user of this protocol to establish appropriate health and safety practices and determine the applicability of regulatory limitations prior to implementing this protocol.~~

5.2 Hazardous Pollutants. Several of the compounds encountered over the course of this protocol maybe irritating or corrosive to tissues (*e.g.*, heptane) or may be toxic (*e.g.*, benzene, methyl alcohol, hydrogen sulfide). Nearly all are fire hazards. Chemical compounds in gaseous emissions should be determined from process knowledge of the source. Appropriate precautions can be found in reference documents, such as reference 13.1.

6.0 Equipment and Supplies

6.1 An OGI camera meeting the following specifications is required:

6.1.1 The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition.

6.1.2 Your OGI camera must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60 grams per hour (g/hr.) from a quarter inch diameter orifice. Alternatively, t~~T~~he OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 ~~grams per hour (~~g/hr.~~)~~ and butane emissions of 18.5 g/hr. at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less.

6.1.3 Documents demonstrating compliance with paragraphs 6.1.1 and 6.1.2 must be retained with other OGI records by the owner or operator or testing organization, as applicable.

6.2 The following items are needed for the initial performance verification of ~~the~~ each OGI camera model configuration, as required by paragraph 6.1.2 and Section 8:

6.2.1 Methane test gas, chemically pure grade (99.5%) or higher and Butane test gas, chemically pure grade (99%) or higher, or~~.~~

6.2.2 ~~Butane test gas, chemically pure grade (99%) or higher.~~A gas that is half methane, half propane at a concentration of 10,000 ppm.

6.2.3 Release orifice, ¼ inch in diameter.

6.2.4 Mass flow controller or rotameter, capable of controlling the gas emission rate within ~~NIST traceable~~ an accuracy of 5 percent.

6.2.5 An industrial fan, capable of adjusting the sustained nominal wind speeds at regular intervals up to 15 m/s, with the ability to maintain a set speed within 20 percent of the target wind speed.

6.2.6 A National Weather Service Station located within 1 mile of the test location. Alternatively, a meteorological station within 1 mile of the location of the testing capable of providing representative data and meeting the following minimum specifications at least once every hour:

6.2.6.1 Ambient temperature readings accurate to at least 0.5 °C, with a resolution of 0.1 °C or less, and a minimum range of -20 to 70 °C.

6.2.6.2 Ambient pressure readings accurate to at least 1.5 millibar (mbar), with a resolution of 0.1 mbar or less, and a minimum range of 700 to 1100 mbar.

6.2.6.3 Wind speed readings accurate to at least 0.1 m/s, with a resolution of 0.1 m/s or less, and a minimum range of 0.1 to 20 m/s.

6.2.6.4 Wind direction readings accurate to at least 5 ~~°C~~degrees, with a resolution of 1 ~~°C~~degree or less.

6.2.6.5 Relative humidity readings accurate to at least 2 percent, with a resolution of 0.1 percent or less, and a minimum range of 10 to 90 percent noncondensing.

6.2.7 A temperature-controlled background large enough for viewing the emissions plume and capable of maintaining a uniform temperature. Uniform is defined as all points on the background deviating no more than 1 °C from the average temperature of the background.

6.2.8 T-type probe thermocouple and readout, accurate to at 1 °C, for measuring the test gas at the point of release.

6.2.9 T-type surface skin thermocouple and readout, accurate to at 1 °C, for measuring the background immediately behind the test gas.

6.2.10 Device to measure the distance between the OGI camera and the release point (e.g., tape measure, laser measurement tool), accurate to at least 2 centimeters (cm), with a resolution of at least 1 cm.

7.0 Camera Calibration and Maintenance

The camera does not require routine calibration for purposes of gas leak detection but may require calibration if it is used for thermography (such as with ΔT determination features).

8.0 Initial Performance Verification and Development of the Operating Envelope

8.1 Determine that the OGI camera meets the specification in Section 6.1. ~~A document demonstrating compliance with this requirement must be retained with other OGI records.~~

8.2 Field conditions such as the viewing distance to the component to be monitored, wind speed, ambient air temperature, and the background temperature all have the potential to impact the ability of the OGI camera operator to detect the leak. It is important that the OGI camera has been tested under the full range of expected field conditions in which the OGI camera will be used.

8.3 ~~An o~~Operating envelopes must be established for field use of the OGI camera. ~~The~~ An operating envelope must be confirmed for all potential configurations that impact the camera's capabilities, such as high sensitivity modes, available lenses, and, in some cases, handheld versus tripod or drone mounted. ~~Conversely, separate operating envelopes may be developed for different configurations.~~ If, in addition to or in lieu of the display on the camera itself, an external device (*e.g.*, laptop, tablet) is intended to be used to visualize the leak in the field, the operating envelope must be developed while using the external device. If the external device will not be used at all times, use of the external device is considered a separate configuration, and ~~the~~ operating envelope testing must be performed for both configurations. Imaging must not be performed when the conditions are outside of the developed operating envelope. Operating envelopes may be developed by a camera manufacturer for a particular OGI camera model and configuration or by others,

8.4 Development of ~~the~~ an operating envelope is to be performed using the test gas composition in either Section 6.2.1 or 6.2.2, flowrate, and orifice diameter described in Section 6.1.2, and must include the following variables:

8.4.1 Delta-T, regulated through the use of a temperature-controlled background encompassing approximately 50 percent of the field of view, with no potential for solar interference;

8.4.2 Viewing distance from the OGI camera to the component being imaged; and

8.4.3 Wind speed, controlled through the use of an industrial fan.

8.5 Determine the operating envelope using the following procedure:

8.5.1 Set up the methane/propane test gas at a flow rate of ~~17~~ 60 g/hr. or setup the methane test gas at a flow rate of 17 g/hr. The same test gas(s) used for demonstrating that the minimum detection limit required in section 6.1.2 must be used when determining operating envelopes.

8.5.2 For this flow rate, the ability of the OGI camera to produce an observable image is challenged by ranges of the variables in Sections 8.4.1 through 8.4.3.

8.5.3 A panel of no less than 4 observers who have been trained using the OGI camera and who have a demonstrated capability of detecting gaseous leaks will observe the test gas release for each combination of delta-T, distance, and wind speed. A test emission is determined to be observed when at least 75 percent of the observers (i.e., 3 of the 4 observers) see the image.

8.5.4 If the pure methane test gas was used, r~~R~~epeat the procedures in Sections 8.5.2 and 8.5.3 using the butane test gas at a flow rate of 18.5 g/hr.

8.5.5 When testing with the pure methane and pure butane test gases, t~~T~~he operating envelope to be used in the field for each OGI camera configuration tested is the more restrictive operating envelope developed between those~~the~~ two test gases.

8.5.6 Repeat the procedures in Sections 8.5.1-8.5.5 for each camera configuration that will be used to conduct surveys in the field.

8.6 The results of the testing to establish ~~the~~ an operating envelope, including supporting videos, must be documented and kept with other OGI records of the organization performing the test. Camera owners must maintain a record of the allowed operating envelope parameters for each camera they own and that record must be readily available to the camera operator.

9.0 Conducting the Monitoring Survey

~~Each site must have a~~ A monitoring plan that describes the procedures for conducting a monitoring survey at each site must be readily available to the camera operator. At a minimum, the monitoring plan must include the following:

9.1 A description of ~~Prior to imaging, the operator must perform~~ a daily verification check to be performed prior to imaging to confirm that the camera is operating properly. This verification must consist of the following at a minimum:

9.1.1 Confirm that the OGI camera software loads successfully and does not display any error messages upon startup;

9.1.2 Confirm that the OGI camera focuses properly at the shortest and longest distances that will be imaged;

9.1.3 Confirm that the OGI camera produces a live IR image using a known emissions source, such as a butane lighter or a propane cylinder;

~~9.1.4 Confirm that the OGI camera can record data and/or leak footage properly by using the~~

~~check in Section 9.1.3 as a test run and saving the resulting file with the survey record; and~~

9.1.~~5~~4 Confirm that the OGI camera can perform the delta-T check function as expected, if this function will be used meet the requirement in Section 9.2.3.

9.2 The ~~site must develop~~monitoring plan must include a procedure for ensuring that the monitoring survey is performed only when conditions in the field are within the operating envelope established in Section 8. This procedure must include the following:

9.2.1 Determination of the camera operator's maximum viewing distance from the surveyed components, based upon wind speed and expected delta-T at the monitoring site. This determination must be made each day a survey is conducted.

9.2.2. Description of how the viewing distance from the surveyed components, the wind speed, and the delta-T will be monitored to ensure that the monitoring survey is conducted within the limits of the operating envelope;

9.2.3 Description of how the operator will ensure an adequate delta-T is present in order to view potential gaseous emissions, (e.g., using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view);

9.2.4 Description of how the operator will recognize the presence of and deal with potential interferences and/or adverse monitoring conditions, such as steam, fog, mist, rain, solar glint, extremely high concentrations of particulate matter, and hot temperature backgrounds;

9.2.5 Description of how the operator will deal with changes in site conditions during the survey, especially as it relates to the camera operator's maximum viewing distance.

~~9.3 The site must conduct monitoring surveys using a methodology that ensures that all the regulated components within the unit or area are monitored. This must be achieved using one of the following three approaches. The approach chosen and how the approach will be implemented must be described in the monitoring plan. The use of a component database can help make the survey process more efficient, but, the component database is not a substitute for the approaches described below.~~

~~9.3.1 Use of a route map or a map with designated observation locations. The map must be included as part of the monitoring plan, with a predetermined sequence of process unit monitoring (such as directional arrows along the monitoring path) depicted or designated observation locations clearly marked.~~

~~9.3.2 Use of visual cues. The facility must develop visual cues (*e.g.*, tags, streamers, or color-coded pipes) to ensure that all regulated components were monitored. The monitoring plan must describe whatvisual cue method is used and how it will be used to ensure all components are monitored during the survey.~~

~~9.3.3 Use of global positioning system (GPS) route tracing. The facility must document the path taken during the survey by capturing GPS coordinates along the survey path, along with date and time stamps. GPS coordinates must be recorded frequently enough to document that all regulated components were monitored. The monitoring plan must describe how often GPS coordinates will be recorded and how the route tracing will ensure all regulated components are monitored.~~

9.3 Your monitoring plan must include procedures to ensure that all equipment leak components as defined in the referencing subpart or permit are monitored. Example procedures include, but are not limited to, a map or electronic database with an observation path or GPS coordinates, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

9.4 The ~~site must develop~~monitoring plan must include a procedure that describes how components will be viewed with the OGI camera. In general, a component should be imaged from at least two different angles, and the operator must dwell on each angle ~~for a minimum of 5 seconds~~ before changing the angle, distance, or focus and dwelling again. For a complex scene of components, the operator must divide the scene into manageable subsections and dwell on each angle~~ for a minimum of 5 seconds per component in the field of view (e.g., for a subsection with 5 components, the minimum dwell time would be 25 seconds)~~. ~~The operator may reduce the dwell time for complex scenes based on the monitoring area and number of components in the subsection as prescribed in Table 14-1, provided the manageable subsection for the angle fills greater than half of the field of view of the camera.~~ The procedure must discuss changes, if necessary, to the imaging mode of the OGI camera that are appropriate to ensure that leaks from all ~~regulated~~ equipment leak components regulated by the referencing subpart or permit can be imaged.

9.5 The monitoring plan must include~~site ownermust have~~ a plan for avoiding camera operator fatigue, as physical, mental, and eye fatigue are concerns with continuous field operation of OGI cameras.~~ The OGI camera operator should not survey continuously for a period of more than 20 minutes without taking a rest break. Taking a rest break between surveys of process units may satisfy this requirement; however, for process units or complex scenes requiring continuous survey periods of more than 20 minutes, the operator must take a break of at least 5 minutes after every 20 minutes of surveying.~~

~~Note: If continuous surveying is desired for extended time periods, two camera operators can alternate between surveying and taking breaks.~~

9.6 The monitoring plan must include~~site owner must have~~ a procedure for documenting monitoring surveys, including:~~.~~

9.6.1 For each monitoring ~~survey~~day or change in facility, record the date and approximate start and end times.

9.6.2 At the start of ~~the survey~~each monitoring day or a change in facility~~, when transitioning to the next major process area, and at the end of the survey~~, record the weather conditions, including ambient temperature, wind speed, relative humidity, and sky conditions.

9.7 The site must have a procedure for documenting fugitive emissions or leaks found during the monitoring survey.

9.7.1 If a leak is found and the leak is not immediately repaired, the leaking component must be tagged for repair or an image obtained to show the location of the leak. If the component is not immediately repaired or tagged, ~~at a minimum~~ capture a digital image or at a minimum a 10-second video clip of the leaking component and keep the video clip or digital image with the rest of the OGI survey documentation. ~~The leaking component must be tagged for repair, and~~ T~~t~~he date, time, and location of ~~the~~ all leaks must be recorded and stored with the OGI survey records. ~~This information can be used to visually assist the operator with locating components that need repair.~~

9.7.2 If no emissions are found, no recorded footage is required to demonstrate that the component was not leaking.

~~9.7.3 At least once each monitoring day, each operator must record a quality assurance (QA) verification video that is a minimum of 5 minutes long. The video must document the procedures the~~

~~operator uses to survey (*e.g.*, dwell times, angles, distances, backgrounds) and the camera configuration.~~

9.8 The ~~site's~~ monitoring plan must describe the process that will be used to ensure the validity of the monitoring data as detailed in Section 11.

10.1 The facility or company performing the OGI surveys must have a training plan which ensures and monitors the proficiency of the camera operators. Training should include ~~classroom~~ instruction and field training on the OGI camera and external devices, monitoring techniques, best practices, process knowledge, and other regulatory requirements related to leak detection that are relevant to the facility's OGI monitoring efforts. ~~If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement.~~ Certified thermographers are exempt from the requirements of paragraphs 10.2 through 10.4.

10.2 Prior to conducting monitoring surveys, camera operators must complete initial training and demonstrate proficiency with the OGI camera and any external devices to be utilized for detecting a potential leak.

10.2.1 At a minimum, the training plan must include the following ~~classroom~~ training elements as part of the initial training:

10.2.1.1 Key fundamental concepts of the OGI camera technology, such as the types of images thecamera is capable of visualizing and the technology basis (theory) behind this capability.

10.2.1.2 Parameters that can affect image detection (*e.g.*, wind speed, temperature, distance,background, and potential interferences).

10.2.1.3 Description of the components to be surveyed and example imagery of the various types ofleaks that can be expected.

10.2.1.4 Calibration, operating, and maintenance instructions for the OGI camera used at the facility.

10.2.1.5 Procedures for performing the monitoring survey according to the ~~site~~ applicable monitoring plan, including the daily verification check; how to ensure the monitoring survey is performed only when the conditions in the field are within ~~the~~ an established operating envelope; the number of angles a component or set of components should be imaged from; how long to dwell on the scene before changing the angle, distance, and/or focus; how to improve the background visualization; the procedure for ensuring that all ~~regulated~~ equipment leak components regulated by the referencing subpart or permit are visualized; required rest breaks; and documenting surveys.

10.2.1.6 Recordkeeping requirements.

10.2.1.7 Common mistakes and best practices.

10.2.1.8 Discussion on the regulatory requirements related to leak detection that are relevant to thefacility's OGI monitoring efforts.

10.2.2 At a minimum, the training plan must include the following field training elements as part of the initial training:

10.2.2.1 A minimum of 10 ~~site~~ 20-minute monitoring surveys with OGI where ~~the~~ trainees ~~is~~

~~observing~~ observe the techniques and methods of a senior OGI camera operator (see definition in Section 3.0) who reinforces the ~~classroom~~ training elements.

10.2.2.2 A minimum of ~~40~~ 5 20-minute monitoring~~site~~ surveys with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and ~~provides~~ providing instruction/correction where necessary.

10.2.2.3 A minimum of 50 20-minute monitoring ~~site~~ surveys with OGI where the trainee performs ~~the~~ monitoring surveys independently with ~~the~~ a senior OGI camera operator trainer present and the senior OGI camera operator ~~provides~~ providing oversight and instruction/correction to the trainee(s) where necessary.

10.2.2.4 A final ~~site~~ 1-hour monitoring survey test where the trainee conducts the OGI survey and a senior OGI camera operator follows behind with a second camera to confirm the OGI survey results. Ninety percent agreement on the number of persistent leaks found or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified ~~The trainee~~ must be achieved ~~zero missed persistent leaks relative to~~for the ~~senior~~ OGI camera ~~operator~~ trainee to be considered authorized for independent survey execution. If the required agreement is not achieved, the senior OGI operator must counsel the trainee and then another 1-hour test performed. If there is a lack of adequate agreement on the second test the trainee must complete the refresher training requirements in paragraph 10.3, before taking the final test again.

10.3 Refresher training.

10.3.1 All OGI camera operators must attend a~~n annual~~ ~~classroom~~ training refresher every three years. This refresher can be shorter in duration than the initial classroom, computer or on-line training but must cover all the salient points necessary to operate the camera (e.g., performing surveys according to the monitoring plan, best practices, discussion of lessons learned throughout the year). OGI camera operators who have not performed any OGI monitoring in the last 12-months, must take refresher training before restarting monitoring.

~~10.2.3~~10.3.2 OGI camera operators with at least 24 hours of OGI monitoring experience in the previous 12-months, but no experience operating under Appendix K, must take refresher training per paragraph 10.3.1 and pass a final test per paragraph 10.2.2.4.

10.4 Performance audits for all OGI camera operators, except senior OGI camera operators, must occur on ~~a quarterly~~an annual basis with at least ~~one~~ three months between two consecutive audits. Performance audits must be conducted according to procedures outlined in the monitoring plan. ~~one of the following procedures~~Performance audit procedures may include, but are not limited to paragraphs 10.4.1 or 10.4.2 of this section:

10.4.1 Performance audit by comparative monitoring. Comparative monitoring in near real-time is where a senior OGI camera operator reviews the performance of the employee being audited by performing an independent monitoring survey.

10.4.1.1 Following the survey conducted by the camera operator being audited, the senior OGI camera operator will conduct a survey of the same equipment of at least 41-hour~~s~~ ~~to ensure that no persistent leaks were missed~~.

10.4.1.2 If there is less than 90% agreement in the number of~~a~~ persistent leaks identified or a difference of more than 1 persistent leak if less than 10 persistent leaks are identified~~ is missed by the camera operator being audited~~, then the camera operator being audited will need to retrain on the monitoring aspects believed deficient. ~~following the field portion of the initial training outlined in Section 10.2.2. For the retraining, the required number of site surveys with OGI is reduced to 5 full side-by-side comparative surveys in Section 10.2.2.2 and 10 supervised surveys in Section 10.2.2.3before t~~The audited camera operator must ~~achieve zero missed persistent leaks on the final survey test to be recertified~~then repeat the paragraph 10.4.1.2 comparative monitoring test.

10.4.2 Performance audit by ~~video~~ observational review. The camera operator being audited must submit unedited and uncut video footage of their OGI survey technique to a senior OGI camera operator for review or a senior OGI camera operator must visually observe the camera operator.

10.4.2.1 The ~~videos~~ observation period must ~~contain~~be at least ~~4~~ 1 hour~~s~~ of~~ survey footage~~.~~ If a single survey is less than 4 hours, footage from multiple surveys may be submitted; however, all videos necessary to cover a 4-hour period must be recorded and submitted for review.~~ The senior OGI camera operator will review the survey technique of the camera operator being audited, as well as look for any missed leaks.

10.4.2.2 If there is less than 90% agreement in the number of~~the senior OGI camera operator finds any~~ persistent leaks ~~missed by the camera operator being audited~~identified or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified or the auditor finds that the survey techniques during the ~~video~~ review do not match the monitoring plan required by Section 9, then the camera operator being audited will need to retrain on the monitoring aspects believed deficient.~~the field portion of the initial training outlined in Section 10.2.2~~.~~ For retraining, the required number of site surveys with OGI is reduced to 5 full side-by-side comparative surveys in Section 10.2.2.2 and 10 supervised surveys in Section 10.2.2.3 before the audited camera operator must achieve zero missed persistent leaks on the finalsurvey test to be recertified.~~ The audited camera operator must then repeat the paragraph 10.4.2 observational test.

~~10.4.3 If a camera operator is not scheduled to perform an OGI survey during a quarter, then the audit must occur with the next scheduled monitoring survey.~~

~~10.5 If an OGI camera operator has not conducted a monitoring survey in over 12 months, then they must repeat the initial training requirements in Section 10.2.~~

11.0 Quality Assurance and Quality Control

11.1 As part of the facility's monitoring plan, the facility must have a process which ensures the validity of the monitoring data. Examples may include routine review and sign-off of the monitoring data by the camera operator's supervisor, periodic comparative monitoring using a different camera operator as part of a continuing training verification plan described in Section 10, or other due-diligence procedures. The monitoring plan must also include specifics of the annual performance audit procedures that will be used to comply with paragraph 10.4.

~~11.2 Daily OGI camera verification must be performed and a brief (5-10 second) video recorded as described in Section 9.1. Additionally, the daily QA verification video for each operator must be recordedas described in Section 9.7.3.~~

~~11.3~~11.2 The following table is a summary of the mandatory QA and quality control (QC) measures in this protocol with the associated frequency and acceptance criteria. All of the QA/QC data must be documented and kept with other OGI records.

Summary Table of QA/QC

Parameter	**QA/QC Specification**	**Acceptance Criteria**	**Frequency**
OGI Camera Design	Spectral bandpass range	Must overlap with major absorption peak of the compound(s) of interest as specified in paragraph 6.1.1.	Once prior to conducting the initial survey~~s~~ of an area and any time the compounds of interest is expected to change due to process changes.
OGI Camera Design	Initial camera performance verification	Must be capable of detecting (or producing a detectable image of) a 10,000 ppmv methane/propane mixture at 60 g/hr. or of methane emissions of 17 g/hr and butane emission of 18.5 g/hr at a viewing distance of 2 meters and a delta-T of 5 °C in an environment of calm wind conditions around 1 m/sor less. (Paragraph 6.1.2)	Once for each camera model or configuration prior to conducting initial surveys.
Developing the Operating Envelope	Observation confirmation	Leak is observed by 3 out of 4 panel observers for specific combinations of delta-T, distance, and wind speed. (Paragraph 8.5)	Once prior to conducting surveys and prior to using a new camera model or configuration.
OGI Camera Functionality	Verification Check	Meet the requirements of Section 9.1 to confirm that the OGI camera software loads successfully and that the camera focuses properly, produces a live IR image, records, and, as applicable, performs the delta-T check function.	Each monitoring day, for each camera prior to conducting a survey with that camera.
Camera Operator Training	Classroom, computer or on-line training	Meet the requirements of Sections 10.2.1 and 10.3 with the issuing of a certificate or record of attendance kept in the employee or OGI records file.	Prior to a camera operator conducting surveys, with a~~n~~ triannual refresher, and after prolonged periods (greater than 12 months) of not performing OGI surveys.
Camera Operator Training	Field training	Meet the requirements of Section 10.2.2 while maintaining the records of facilities ~~visited~~ monitored by the trainee in the employee or OGI records file along with a certificate or record of completion ~~issued upon the achievement of zero missed persistent leaks~~ of the final survey test specified in paragraph 10.2.2.4 with the date of the survey recorded.	Prior to a camera operator conducting surveys and after prolonged periods (greater than 12 months) of not performing OGI surveys.

~~OGI Camera Operator Performance~~	~~QA verification video~~	~~Record a video that is a minimum of 5 minutes long that documents the procedures the operator uses to survey *(e.g.*, dwell times, angles, distances, backgrounds) and the camera configuration.~~	~~Each monitoring day.~~
OGI Camera Operator Performance	~~Quarterly~~ Annual performance audits	Comparative monitoring: ~~No missed~~Ninety percent agreement on the number of persistent leaks over a ~~4~~1-hour survey as determined by a senior OGI camera operator's survey. OR Video review: Ninety percent agreement on the number of ~~No missed~~ leaks as determined by a senior OGI camera operator and OGI survey technique in submitted videos matches the requirements in Section 9. OR Other audit procedure specified in the applicable monitoring plan.	Every ~~3~~ 12 months, with at least ~~1~~ 3 month between consecutive audits.

12.0 Recordkeeping

12.1 Records required by this Appendix must be kept~~The facility must keep the records required by this protocol~~ for a period of 5 years, unless otherwise specified in an applicable subpart.

12.2 The following records must be maintained, as applicable.~~The facility must maintain the following records in a manner that is easily accessible to all OGIcamera operators:~~ Applicable site monitoring plans and operating envelope limitations must be readily accessible to the camera operators.

12.2.1 Complete site monitoring plan with all the required elements;

12.2.2 Initial OGI camera performance verifications;

12.2.3 Camera maintenance and calibration records over the lifetime of the OGI camera; and

12.2.4 The OGI camera operating envelope limitations.

12.3 All data supporting development of the operating envelope must be maintained by the organization that develops an operating envelope.

12.4 The training plan, and for each OGI camera operator, the following records must be maintained by the employer of the OGI camera operator or the owner or operator of a location being surveyed, as applicable. These may be kept in a separate location for privacy but must be easily accessible to program administrators and available for review if requested by the Administrator: For certified thermographers, these records are not required but a record of the thermographer's certification and date of its expiration is required.

12.4.1 The date of completion of initial OGI camera operator classroom, computer or on-line training;

12.4.2 The date of the passed final ~~site~~ survey test following the initial OGI camera operator field training;

12.4.3 The number and date of all training surveys performed, and if the survey is part of initial field training or retraining, notation of whether the survey was performed by observing a senior OGI camera operator, side-by-side with a senior OGI camera operator, or with oversight from a senior OGI camera operator;

12.4.4 Performance audit methodologies.

~~12.4.4~~12.4.5 The date and results of ~~quarterly~~ annual performance audits; and

~~12.4.5~~12.4.6 The date of any~~the annual classroom~~ training refresher.

12.5 Monitoring survey results shall be kept ~~in a manner that is accessible to those technicians executing repairs~~ and at a minimum must contain the following:

12.5.1 Daily verification check;

~~12.5.2 Camera operator's maximum viewing distance for the day, based upon wind speed and expected delta-T at the monitoring site.~~

~~12.5.3~~12.5.2 Identification of the ~~site~~facilities surveyed and the survey date and start and end times;

~~12.5.4~~12.5.3 Name of the OGI camera operator performing the survey and identification of the OGI camera used to conduct the survey. The identification of the OGI camera can be the serial number or an assignedname/number labeled on the camera, but it must allow an operator or inspector to tie the camera back to the records associated with the camera (*e.g.*, maintenance, initial performance verification);

~~12.5.5~~12.5.4 Weather conditions, including the ambient temperature, wind speed, relative humidity, and skyconditions, at the start of the ~~survey~~monitoring day~~,~~ and when ~~transitioning to the next major process area~~changing the facility being surveyed~~, and at the end of the survey~~;

12.5.5 Video footage or digital photo of any leak detected and not immediately repaired or tagged along with the date, time, and component location of all leaks detected. This video or digital record shall be maintained in a manner that is accessible to those technicians executing repairs; and

12.5.6 Records identified in the monitoring plan to demonstrate that all equipment leak components are monitored per paragraph 9.3.~~The daily QA verification video for each operator; and~~

12.5.7 ~~GPS coordinates for the route taken, if Section 9.3.3 is used to ensure all regulated components are monitored.~~

13.0 References

13.1 U.S. Department of Health and Human Services. (2010). NIOSH Pocket Guide to Chemical Hazards. NIOSH Publication No. 2010-168c. Also available from https://www.cdc.gov/niosh/docs/2010-168c/default.html.

13.2 U.S. Environmental Protection Agency. (2021). Technical Support Document: Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K).

13.3 U.S. Environmental Protection Agency. (2020). Optical Gas Imaging Stakeholder Input Workshop Presentations and Discussion; Summary Letter Report.

13.4 Zeng, Y., J. Morris, A. Sanders, S. Mutyala, and C. Zeng. (2017). Methods to Determine Response

Factors for Infrared Imagers used as Quantitative Measurement Devices. *Journal of the Air &Waste Management Association*, *67*(11), 1180-1191. DOI: 10.1080/10962247.2016.1244130. Availableonline at: https://doi.org/10.1080/10962247.2016.1244130.

13.5 Zimmerle, D., T. Vaughn, C. Bell, K. Bennett, P. Deshmukh, and E. Thoma. (2020). Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. *Environmental Science & Technology*, *54*(18), 11506-11514. DOI: 10.1021/acs.est.0c01285.

~~*14.0 Tables, Diagrams, and Flow Charts*~~

~~Table 14-1. Dwell Time (in seconds) by Subsection Area and Scene Complexity~~

	~~Components in Subsection~~				
~~Monitoring Area (m^2)~~	**~~2-3~~**	**~~4-5~~**	**~~5-10~~**	**~~10-20~~**	**~~>20~~**
~~0.125~~	~~5~~	~~10~~	~~15~~	~~20~~	~~25~~
~~0.25~~	~~5~~	~~15~~	~~20~~	~~25~~	~~30~~
~~0.50~~	~~10~~	~~15~~	~~25~~	~~30~~	~~*~~
~~1.0~~	~~10~~	~~20~~	~~30~~	~~*~~	~~*~~
~~>1.0~~	~~*~~	~~*~~	~~*~~	~~*~~	~~*~~

~~* The camera operator must either reduce the subsection volume, the scene complexity, or both by moving closer to the components or changing the viewing angle.~~

~~The operator must divide the scene into manageable subsections and image each subsection from at least two different angles. The dwell time for each angle must be a minimum of 5 seconds per component in the field of view. The operator may reduce the dwell time based on the monitoring area and number of components as described in this table, provided the manageable subsection for the angle fills greater than half of the field of view of the camera. The depth of components within the monitoring area must be less than 0.5 meters.~~

Attachment C

Cost Effectiveness Evaluation for Retrofit of Existing Pneumatic Controllers

Introduction

The purpose of this analysis was to identify the minimum number of controllers that would be cost-effective to retrofit at existing well sites, central tank batteries, and compressor stations based on API member cost information. We utilized EPA's model plant analysis, which was provided by EPA in a Microsoft Excel Workbook *'Pneumatic Controllers Costs and Emissions.xlsx'.* Our review of the model plant analysis determined some assumptions made by EPA should be re-evaluated. Our analysis includes the following updates:

- *Assumptions on the types of reliable technologies available to retrofit pneumatic controllers to non-emitting,*
- *Assumptions of the capital and annual operating costs for these technologies,*
- *Assumptions regarding the ratio of pneumatic controller types at an average facility (what EPA refers to as a model plant), and*
- *Assumptions on the emission factor applied for intermittent controllers that would be part of a monitoring and repair program (which EPA also proposed under fugitive emission monitoring).*

Costs

EPA assumed companies would use grid power or solar systems to power electric controllers. For grid power scenarios, EPA costs were limited to the costs of controllers ($4,000 each) and a control panel for grid connection ($4,000). For solar power scenarios, EPA costs were limited to the cost of electric controllers ($4,000 each), a control panel ($4,000), a single 140 W solar panel ($500), and 100 Amh batteries ($400 each). EPA also included installation and engineering costs based on 20% of equipment costs, with total estimated installation costs varying between $4,420 and $8,040. EPA did not include any annual operating or maintenance costs within their assumptions.

API members have converted natural gas driven pneumatic controllers to compressed instrument air systems powered by the grid (when accessible) or natural gas/diesel generators.[1] Costs associated with a typical instrument air system include a regenerative dryer, inlet filter, tank to store compressed air, insulated enclosure for the compressor and dryer, junction box, controllers for the compressor system, and voltage boosters. Additional costs for solar based systems would include higher cost gel or AGM batteries, sufficient number of batteries, and higher numbers of solar panels required in areas of less sunlight such as for Wyoming and North Dakota. Additional costs associated with use of natural gas or diesel generators to power instrument air systems might also include monthly rental fees.[2] An instrument air system typically also requires annual maintenance at a cost of between $2,000 and $4,000 per year depending on the size of the system.

Through a blinded survey conducted a third party, API members provided cost data for converting pneumatic controllers to non-emitting. For smaller facilities, the average cost for a grid powered

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[1] API members are only in initial phases of testing the reliability of solar based instrument air systems and costs are not available for a smaller installation.

[2] Monthly rental fees for a third-party generator can run between $8,000 upwards of $25,000 based on the size of the facility. We did not include these additional fees in this analysis.

instrument air system was estimated at $51,000 and for a natural gas generator powered instrument air system around $60,000. These costs include equipment and installation costs. There are also annual maintenance costs associated with both types of systems as mentioned above. For our analysis, we assume an average annual maintenance cost of $3,000.

Count of Controllers

EPA assumed that for existing site retrofits the small, medium and large model plants each contained a high bleed pneumatic controller. This is an incorrect assumption, which is supported by data reported to EPA pursuant to 40 CFR Part 98, subpart W. Data extracted from Envirofacts for the 2020 calendar year clearly shows the breakdown of high bleeds is only 1% for the production segment and 3% for the gathering and boosting segment as summarized in Table C-1. For our analysis, we utilized the assumption that there are 30% continuous low bleed controllers and 70% intermittent controllers at an existing facility.

Table C-1. Counts of Pneumatic Controllers Reported for the 2020 Calendar Year pursuant to 40 CFR Part 98, Subpart W

2020 Reporting Year GHGRP Data	Onshore petroleum and natural gas gathering and boosting [98.230(a)(9)]		Onshore petroleum and natural gas production [98.230(a)(2)]	
Device Type	**Count**	**% of total**	**Count**	**% of total**
High-Bleed Pneumatic Devices	4,067	3%	11,292	1%
Intermittent Bleed Pneumatic Devices	93,202	69%	592,456	72%
Low-Bleed Pneumatic Devices	38,153	28%	221,612	27%
Total	135,422	100%	825,360	100%

Emission Factors

As documented in API's Compendium of GHG Emission Methodologies for the Natural Gas and Oil Industry[3] in Table 6-15:

- The average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or the monitoring status is unknown.
- The normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program.

When intermittent controllers are properly functioning, gas is typically emitted only when the controller actuates. Since EPA has proposed to include intermittent controllers within the fugitive emission monitoring requirements, the intermittent controller would be monitored routinely and repaired or replaced if malfunctioning. Therefore, the more appropriate emission factor that should be utilized for

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[3] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

the pneumatic controller analysis is the properly functioning intermittent controller emission factor of 0.28 scf whole gas/controller-hr and not the average emission factor of 9.2 scf whole gas/controller-hr that EPA applied in their analysis.

Results

Our review indicates that it is not cost effective (as prescribed by EPA) to retrofit gas driven controllers to non-emitting unless there are at least 15 to 30 controllers at an existing site, depending on the single or multi-pollutant approach that EPA typically uses for evaluation. Our results, which follow the analysis format outlined by EPA, are provided in Table C-2.

Table C-2. Cost-Effectiveness Determination for the Minimum Number of Controllers that Should be Considered for Retrofit

Model Plant	Control Option[a]	Count of Controllers[b]	Emissions Reduction- Per Facility (tpy)[c]		Capital Cost[d]	Without Savings					With Savings				
						Annual Cost ($/yr)[d]	Cost Effectiveness ($/ton)		Multipollutant Cost Effectiveness ($/ton)		Annual Cost ($/yr)[d]	Cost Effectiveness ($/ton)		Multipollutant Cost Effectiveness ($/ton)	
			VOC	Methane			VOC	Methane	VOC	Methane		VOC	Methane	VOC	Methane
Minimum # of controllers Multi-Pollutant	Grid power Instrument air system	15	0.66	2.36	$51,000	$8,600	**$13,980**	**$3,886**	$6,990	$1,943	$8,198	**$13,327**	**$3,705**	**$6,664**	**$1,852**
	Natural gas generator instrument air system		0.66	2.36	$60,000	$9,588	**$15,586**	**$4,332**	$7,793	$2,166	$9,186	**$14,933**	**$4,151**	**$7,467**	**$2,076**
Minimum # of controllers Single Pollutant	Grid power instrument air system	30	1.31	4.72	$51,000	$8,600	**$6,990**	**$1,943**	$3,495	$971	$7,797	**$6,337**	**$1,762**	**$3,169**	**$881**
	Natural gas generator instrument air system		1.31	4.72	$60,000	$9,588	**$7,793**	**$2,166**	$3,896	$1,083	$8,785	**$7,140**	**$1,985**	**$3,570**	**$992**

a. Grid Power Instrument Air Systems are assumed to be for locations with available onsite grid power access (assuming a step-down transformer is in place).

b. Counts of Controllers include 30% low bleed and 70% intermittent bleed, which is consistent with trends reported to EPA under 40 CFR Part 98, subpart W for the 2020 calendar year.

c. Emission baseline updated to denote use of properly functioning intermittent controller based on Table 6-15 of the Compendium of GHG Emission Methodologies for the Natural Gas and Oil Industry. This change will appear in the Emission Reduction - Per Facility Columns for methane and VOC.

d. Costs updated to reflect API member company data presented in Table 3 of API comment document (refer to Comment 2.8) based on technologies currently being deployed. This includes an additional $3,000 of annual maintenance costs to ensure instrument air system is functioning properly. Cost info updates are denoted by red font.

Attachment D

API Comments on EPA's Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks

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November 16, 2021

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Re: API Comments on EPA's Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks

Dear Ms. Weitz,

The American Petroleum Institute (API) appreciates the opportunity to review and provide comments on the proposed updates the U.S. EPA is considering for estimating greenhouse gas (GHG) emissions for the 2022 GHG Inventory (GHGI). The current set of comments addresses the methodologies outlined in EPA's September 2021 technical memoranda on: (a) abandoned oil and gas wells; (b) post-meter emissions; (c) use of Gas Star and Methane Challenge reductions; (d) midstream activity data; and (e) emissions from anomalous well events.

API represents all segments of America's natural gas and oil industry. API was formed in 1919 as a standards-setting organization. In our first 100 years, API has developed more than 700 standards to enhance operational and environmental safety, efficiency, and sustainability. Our 600 members produce, process, and distribute most of the nation's energy. Most of our members will be directly impacted by the way emissions from their operations are depicted in the national GHGI.

API's aim is to make sure that the GHGI emission estimates used are based on the best and most current data available, reflect actual industry practices and activities, and are technically correct. To assist EPA in the endeavor API has participated in EPA's stakeholders' process and expert review phases of the GHGI development process, providing comments and recommendations on the agency's proposed methodologies. API appreciates the continued engagement with EPA through the multi-stakeholders process.

API's comments below are designed to provide feedback on the information the Agency is seeking from industry along with additional input to inform the proposed updated methodologies. For some of the updates under considerations API is providing supplemental information while for others API recommends that EPA reconsider the merit of adopting the proposed revised methodologies, at this time, without allowing additional time for obtaining information about relevant practices.

Updating Abandoned Wells methodology[1]

- API commented previously on Abandoned Wells emissions when EPA introduced the update for the 2018 GHGI. API noted that the studies conducted so far have limited geographical coverage and may not be nationally representative. To clarify, EPA uses the "entire US" emission factors from the Townsend-Small study, which include the much higher Eastern US (Appalachian - Ohio) emission factors. They then use these same Eastern US factors from Townsend-Small coupled with emissions from Kang 2016 to develop EF's for Appalachian basin abandoned wells. API recommends that EPA should use the lower "western US" emission factors for abandoned wells outside of the Appalachian basin.

- Additionally, the Townsend-Small Appalachia data are dominated by one well with emissions of 146 grams/hr that is about an order of magnitude higher than any other well, plugged or unplugged, in the Townsend-Small data. API contends that it is not appropriate to include this well in the emission factor for the entire US. Also, to date no emissions data are available from the state of Texas or many other major producing areas, calling into question the representativeness of the extrapolation of the results of the current studies to a nationwide estimate of the contribution of CH_4 emissions from Abandoned Wells to the GHGI.

- API requests from EPA a better explanation of how it estimated the number of 1.1 million historical abandoned wells, which are not captured in the Enverus database. Moreover, API maintains that EPA should not assume that all historical (pre-Enverus) wells are unplugged, without further supporting information. Looking at the restructured Enverus data at the end of 1975, which is the date EPA used to develop its estimate of historical (pre-Enverus) wells, indicates that 72% of the wells that would be classed as 'abandoned' by the criteria in Table 3 of the 2022 memo are shown as actually 'plugged and abandoned'. Hence, EPA should not ignore the Enverus data in favor of unsupported assumptions.

- API contends that an alternative estimate of historically abandoned wells could be based on data for 'undocumented orphan wells' provided in the 2019 report issued by the Interstate Oil & Gas Compact Commission (IOGCC)[2]. According to the IOGCC 2019 report the total estimated number of undocumented orphan wells reported by the states is between 210,000 and 746,000 (*as shown in Table 1. Total Idle and Orphan Wells: All Surveyed States and Provinces (2018)).*

- API also asks EPA to provide greater insight into the process of restructuring of the Enverus data set and the treatment of dry wells. API notes that the designation of "Dry Wells" in the Enverus database indicate a production type rather than a status type and EPA's approach of considering all wells with no cumulative production as abandoned wells is likely leading to

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[1] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-abandoned-wells_sept-2021.pdf

[2] IOGCC, 2019, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies; https://iogcc.ok.gov/sites/g/files/gmc836/f/documents/2021/2020_03_04_updated_idle_and_orphan_oil_and_gas_wells_report.pdf

double counting of dry wells in the abandoned well category since they are embedded in the well status counts. Furthermore, EPA's assumption that dry wells are unplugged is neither consistent with the Enverus data nor State plugging requirements. Current Enverus data shows that 93% of dry holes are plugged. Texas requires the same plugging standards for dry holes as for idle production wells and other State requirements are believed to be similar.

- Many of the largest producing states have regulations in place spelling out emissions, discharge or integrity requirements that must be met when a well is non-producing. API stipulates that the simple assignment of the 'unplugged' designation to all the status codes that are not 'Excluded' or 'Plugged and Abandoned' (P&A) overlooks the potential impacts of such regulations and is therefore inaccurate. Such regulations, even if not directly promulgated to control volatile emissions, have the potential for lower emission rates from wells that are subject to regulation when inactive*. See Appendix 1 for matrix of state requirements for inactive wells.* API is looking forward to engaging with EPA on the impact of existing regulatory requirements on emissions from abandoned and inactive wells.

- API's analysis of Enverus data does not validate the information in Table 3 of the 2022 Abandoned Wells Update Memo as representative of calendar year 2019. However, the counts in Table 3 are broadly similar to API's analysis of current date Enverus well counts. API requests that EPA should validate that their modified query of the Enverus database for 2019 counts is correct and provide this information to stakeholders in an updated Table 3 if changes are substantive.

- Moving forward API recommends that EPA should continue to use the Enverus production type field, where available, to classify wells into gas vs. oil and should also use the Enverus P&A status for determining what dry holes are unplugged. API further recommends that EPA should continue to use the cumulative production coupled with the well status and production type information to determine the count of dry wells*.*

- API is not aware of alternative, high quality, sources of data readily available to inform the count of abandoned wells or the split into plugged and unplugged categories

Post meter emissions[3]

- API acknowledges EPA's proposed intent to add estimates from post-meter residential, commercial, and industrial customer methane emissions as well as certain natural gas vehicle emissions in accordance with guidance provided in the 2019 Refinement to the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories for natural gas systems (IPCC 2019).

- API recognizes that while post-meter emissions will be part of the Natural Gas Systems chapter of the GHGI, it requests that the data be provided as its own "line item" within natural gas

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[3] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-post-meter_sept-2021.pdf

systems. It should not be included in the distribution segment, which ends at the customer meter.

- For residential post meter emissions, EPA intends to base its estimate on the Fischer et. al. (2018) report[4], which measured CH_4 leak emissions from 75 homes that use natural gas in California. This study is used as the basis for the estimate provided in the CARB state GHG inventory. API observes that the limited regional nature of the 2018 data used for CARB's estimate is not sufficiently large to represent residential gas use and potential CH_4 emissions nation-wide. In the absence of better data API suggests that EPA consider a bifurcated approach that uses other available regional data, such as the Merrin and Francisco (2019), outside of California.

Use of GasStar and Methane Challenge reductions in GHGI[5]

- EPA is assessing the applicability of reductions reported under GasStar and the Methane Challenge voluntary programs for the accounting of emission reductions data to prevent double counting. API supports EPA's intent to remove the current time series of GasStar emission reductions and replace them with an updated series for the span of 1990-2019 for those sources for which 'potential to emit' methodology is still used in the GHGI estimates.

- API objects to EPA's proposal to revise the GasStar emission reductions dataset by applying sunset dates of 7 or 10 years for those emissions, rather than assume that the reductions are permanent. API members, who are also GasStar partners, contend that sunsetting of the "reductions" in the GasStar program were not necessarily related to any lack of efficacy, or "decay", of the reduction or control measures put in place. Adoption of the sunset dates' methodology reflected the goal of the GasStar program to drive additional reductions overtime. Thus it was the credits offered in the programs that were retired, with no indications that the emission reductions ceased or that emissions increased.

Applying midstream activity data updates[6]

- EPA is considering using the Enverus Midstream and PHMSA data to update certain activity data. This would result in potentially significant changes to counts of processing plants, gathering and boosting compressor stations, gathering pipeline miles, and transmission pipeline miles, with a smaller change to the count of transmission compressor stations.

- API support the continued use of current sources of activity data previously used in the GHGI which relied on data reported through the GHG Reporting Program (GHGRP) and other

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[4] Marc L. Fischer, Wanyu R. Chan, Woody Delp, Seongeun Jeong, Vi Rapp, Zhimin Zhu. An Estimate of Natural Gas, Methane Emissions from California Homes. Environmental Science & Technology 2018, 52 (17), 10205–10213; .https://pubs.acs.org/doi/10.1021/acs.est.8b03217

[5] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-gas-starmc_sept-2021.pdf

[6] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-activity-data_sept-2021.pdf

regulatory programs. API does not support moving to the Enverus database without further review and explanation on how the database was developed.

- The current activity data in the GHGI has been developed from regulatory data ensuring alignment of, and achieving consistency with, reported industry data. For example, GHGI 2019 data accounts for 667 natural gas processing plants and represents about a 25% higher count than that available from the EIA 757 survey (479 in EIA, 2017)[7], or the 449 facilities that reported to GHGRP in 2019. This difference may be explained by the regulatory thresholds for the reporting facilities. To compare, the Enverus Midstream database indicates that there are more than double natural gas processing plants (1021 - see Table 6 of EPA September 2021 memo). API is concerned that such a large discrepancy indicates that there might be double-counting of processing plants, which may call into question the reliability of the entirety of Enverus Midstream data.

- API has previously supported the use of PHMSA data for midstream activities and continues to support the use of PHMSA for storage well counts. API affirms that using the PHMSA data uses actual counts versus the current GHGI estimation.

Anomalous Events including Well Blowout and Well Release Emissions[8]

- EPA is considering expanding the estimation of anomalous events from just onshore oil well blowouts to including onshore oil and gas well blowouts and releases. EPA intends to use the existing emission factor and TX RRC extrapolated activity data to estimate blowouts and releases.

- API is concerned over the use of a single emission factor for both oil and gas wells, as well as representing both blowouts and releases. API is seeking more information (with a specific citation) to the “Industry Review Panel” that originally proposed the 2.5 mmcf/event emission factor. API calls on EPA to more precisely distinguish between a well blowout and a well release and explain what the existing distinction is.

- API requests that EPA clarify whether there is a possibility of developing emission factors that are based on the length of the blowout rather than the events count, and further consider whether the TX RRC database can be leveraged to link the activity factor to a set of scaled emission factors, i.e., based on those same qualitative measures by which EPA was able to consider the relative frequencies of blowouts and releases.

- Though API has requested more information regarding the 2.5 mmcf/event EF, API recommends that moving forward for now, EPA continue to apply the current EF (2.5 mmcf/event) to onshore oil well blowouts only. API does not support expanding the use of the current EF to either oil well releases or to natural gas well blowouts and releases without getting

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[7] https://www.eia.gov/naturalgas/ngqs/#?report=RP9&year1=2017&year2=2017&company=Name

[8] https://www.epa.gov/system/files/documents/2021-10/2022-ghgi-update-well_blowouts_releases.pdf

more information, better leveraging TX RRC database, or scaling EFs based on event and well types.

- API supports using measured emissions data or engineering estimates for unique major anomalous leak events when they occur. Such major events need to be evaluated on a case-by-case basis, per IPCC guidelines[9].

API welcomes EPA's willingness to work with industry to improve the data used for the national inventory. API encourages EPA to continue these collaborative discussions including making progress in addressing the new data collected by the API field study on Pneumatic Controllers emissions.[10] As indicated before, API is available to work with EPA to make best use of the information available under the GHGRP, or other appropriate sources of information/data, to improve the national greenhouse gas emission inventory. To that end we await hearing about the agency's next steps with regard to incorporating revisions to the GHGRP.

Sincerely,

Marcus J Koblitz

Marcus Koblitz
Policy Advisor, Climate & ESG Policy
Corporate Policy
koblitzm@api.org

cc. Mark DeFigueiredo, DeFigueiredo.Mark@epa.gov

Attach: Appendix 1. Matrix of State and Federal Well Abandonment Programs

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[9] 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 Energy, 4.2.2.3 CHOICE OF EMISSION FACTOR1 B 2 a vi Other

[10] API, *Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States*, March 2020 (submitted to EPA by memorandum on July 2, 2020)

Attachment B

Previous API Comments on Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems;

Docket No. EPA-HQ-OAR-2023-0234

Proposed Subpart W Revisions

API American Petroleum Institute
AXPC
IPAA INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA
THE PETROLEUM ALLIANCE OF OKLAHOMA
AFPM

October 2, 2023

<u>Submitted electronically to docket No. EPA-HQ-OAR-2023-0234</u>

Jennifer Bohman

Climate Change Division, Office of Atmospheric Programs (MC-6207A)
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Docket No. EPA-HQ-OAR-2023-0234

Dear Ms. Bohman:

The American Petroleum Institute, the American Exploration & Production Council, Independent Petroleum Association of America, The Petroleum Alliance of Oklahoma, and the American Fuel and Petrochemical Manufacturers (collectively "Industry Trades") appreciate the opportunity to offer comments to the U.S. Environmental Protection Agency (EPA) on the proposed “Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems” (proposed on August 1, 2023). For perspectives of offshore operators, the Industry Trades encourage EPA to also review the Offshore Operators Committee (OOC) letter and incorporate them by reference herein. With this submittal, the Industry Trades seek to continue our participation in the rulemaking process as a collaborative stakeholder by providing meaningful solutions to simultaneously address EPA’s goals while addressing the burden of data collection (and identifying potential unintended consequences) that could result if the rulemaking is finalized as proposed.

The oil and natural gas industry has participated as key collaborative stakeholders, advancing the EPA Greenhouse Gas Reporting Program (GHGRP) since its inception by contributing expertise and proposing alternatives that reflect the reality of the industry and its evolving day-to-day operating practices. The Industry Trades have focused on providing information that will help inform decision makers and the public about various challenges to data collection and reporting required by the rule, which includes safety, accuracy, and feasibility concerns, as well as the need to protect sensitive information and to ensure that reporting requirements are placed on the correct reporters.

These comments on EPA’s proposed revisions to Subpart W reflect our continued interest in the evolution of the GHGRP to provide an accurate accounting of greenhouse gas (GHG) emissions from facilities across the full value chain of the oil and natural gas industry. Our comments cover concerns and recommendations in the wide range of sectors that relate to the operations of our collective members.

Docket ID No. EPA-HQ-OAR-2023-0234
October 2, 2023

INDUSTRY TRADES' INTERESTS

The **American Petroleum Institute (API)** is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader convening subject matter experts from across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 800 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Additionally, API has a history of working with EPA to refine and improve data collection, emission estimation and emission reporting under various subparts of the GHGRP. API has worked with both EPA and the regulated industry for more than two decades in developing methodologies for estimating greenhouse gas emissions from oil and natural gas operations. API's first *Compendium of GHG Emissions Methodologies for the Oil and Natural Gas Industry* (the *Compendium*) was published in 2001. As reflected in EPA's efforts to revise the GHGRP and API's recent publication of a 4th edition of the *Compendium (November 2021)*, methodologies to estimate and measure greenhouse gas emissions are continually evolving.

The **American Exploration & Production Council (AXPC)** is a national trade association representing 30 of the largest independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of providing positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

The **Independent Petroleum Association of America (IPAA)** represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, which will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The **Petroleum Alliance of Oklahoma** (The Alliance) represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. The Alliance's members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas and play an essential role in providing products and solutions to improve human health and welfare, power the global economy, and make modern life possible. Abundant, clean-burning natural gas has enabled the United States to become the global leader in greenhouse gas emissions reductions. The Alliance's members have and will continue to deploy technologies that result in meaningful greenhouse gas emission reductions through innovative solutions and breakthrough technologies while meeting the energy demands of today and the future.

American Fuel and Petrochemical Manufacturers (AFPM) is a national trade association whose members comprise most U.S. refining and petrochemical manufacturing capacity. AFPM is the leading trade association representing the makers of the fuels that keep us moving, the manufacturers of the petrochemicals that are the essential building blocks for modern life, and the midstream companies that get our feedstocks and products where they need to go. To receive necessary materials and to move their essential products to satisfy growing demand, AFPM members depend on the timely development of, and enhancements to, transportation infrastructure such as pipelines.

The Industry Trades appreciate EPA's engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize changes to Subpart W that improve accuracy without imposing undue burden on the industry, reflect technological and scientific improvements in methodologies, and incentivize the industry's ongoing efforts to reduce emissions.

The Industry Trades' Comments on EPA's Proposed "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems"

Docket ID: EPA-HQ-OAR-2023-0234

October 2, 2023

Summary of Priority Items

The Industry Trades support certain aspects of the proposed revisions to Subpart W and remain committed to working with the Environmental Protection Agency (EPA) and the Administrator to improve the accuracy of Subpart W reporting in a cost-effective manner, while encouraging continued progress toward reducing greenhouse gas (GHG) emissions. The Industry Trades support accurate emissions reporting for many reasons, however it is particularly important given that reported emissions will form the basis of assessed methane fees as a Waste Emissions Charge (WEC), implemented under the Inflation Reduction Act (IRA). As such, these proposed changes create a potentially significant financial impact on the Industry Trades. Therefore, the Industry Trades provide these comments with a goal of improving accuracy of reported emissions through requirements that are appropriate, implementable, and reflective of actual emissions.[1] The comments herein focus on technical and feasibility challenges with specific provisions that EPA included in the proposed Subpart W rule revisions, while providing viable alternatives that support accurate emissions reporting.

The Industry Trades continue to strongly encourage EPA to find ways to make Subpart W less prescriptive and therefore better poised to not just accommodate but encourage the use of rapidly evolving technologies to detect and minimize emissions.

In addition to our technical comments, the Industry Trades have identified four overarching priority items within the proposed rules that if satisfactorily amended, will allow industry to attain the maximum potential methane mitigation and reduce public confusion. These high priority items are as follows:

1. **Achieve greater inter- and Intra- agency regulatory harmonization and coordination**:

   There are multiple federal agencies and distinct departments within agencies that have pending or proposed regulations, guidance, or frameworks directly and indirectly related to methane emissions applicable to our industry, as listed below:

   a. EPA – New NSPS OOOO b/c regulations
   b. EPA – Revisions to GHG Subpart W methane reporting
   c. EPA – Pending Methane Emissions Reduction Plan (MERP) implementation regulations
   d. Treasury Department – Section 45V regulations for hydrogen production tax credit, with the treatment of differentiated natural gas
   e. DOT/PHMSA – LDAR Rule
   f. DOI/BLM – Waste Prevention Rule
   g. DOE/Argonne – GREET Model, used as the basis for calculating GHGs associated with hydrogen production for eligibility for the Section 45V tax credit
   h. DOE – Differentiated Gas Framework
   i. State Department – International methane MRV standard (with DOE)
   j. State Department – Global discussions on an EU Import standard and global methane policy

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[1] Citations provided in this comment letter refer to the proposed rule, unless indicated otherwise. The structure and order of our comments does not necessarily reflect the individual comments' importance to the Industry Trades and their members. The Industry Trades believe all of its comments will help ensure the rule's integrity and deserve serious consideration.

Across all of this methane-related policy making, the Industry Trades identify a potentially high risk for inconsistent methodologies or reporting structures.

In addition, many states – especially New Mexico and Colorado – have already implemented regulations to mitigate emissions across the oil and gas industry; these likely conflict with the final NSPS OOOOb, EG OOOOc and Subpart W reporting requirements.

We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself. Below are a few examples that are articulated in our comments:

- "Other large release events" should be governed by the Methane Rules Super Emitter Response Program ("SERP"), not by an additional and separate Subpart W notification process.
- The "Other large release event" threshold for pipelines should align with the PHMSA incident threshold.
- Compressor vent measurements should align with the Methane Rules. Subpart W should not mandate additional measurements for those sources.
- Flare requirements should not extend beyond 60.18 "General control device and work practice requirements" and the Methane Rules.
- Combustion emissions for all oil and gas segments should be reported under Subpart C, which is the subpart under which *all other industries* report fuel combustion emissions.

2. **Incentivize Cost-Effective Advanced Methane Detection through Technology Agnostic Rules:**

Advanced methane detection technologies and flexibility to implement them are critical to the industry's ability to fully realize methane emissions reductions. Many operators have invested in technological advancements and have deployed and tested the technologies over many years, demonstrating the success of advanced programs and reaching a firm understanding of their operation and deployment. If this component of the suite of methane rule makings, including in Subpart W, is not expanded, the remaining rules will fail to realize the emission reduction goals.

3. **Accommodate Empirical Data, as a Demonstration of Emission Reductions**:

Provisions must be built into the Subpart W rule so that each operator can demonstrate actual reductions; this would promote consistency, transparency, and accuracy in emissions reporting. For example, reporters are precluded from using readily available empirical data (such as engine performance tests) and are instead required to use static emission factors that were based on limited data sets, which will not be reflect emissions reductions and will disincentivize emission reductions. The Industry Trades have noted throughout our comments where EPA must adjust the rule to accommodate empirical data.

4. **Maintain EPA's GHGRP and Subpart W within it as the Authoritative Source of Reported Emissions**:

There are increasing instances of conflict between Subpart W methodologies with those of permitting agencies, which also conflict with current and proposed LDAR requirements and other state and federal GHG reporting structures. EPA must strive for consistency across all GHG reporting frameworks in order to promote stakeholders' trust and confidence in the data.

In addition to the high priority items listed above, the summary below includes the key comments that are generally applicable to many of EPA's proposed revisions to the Subpart W rule:

- **Many proposed Subpart W requirements would impose high implementation burdens for small accuracy improvements for most sources and overall reported emissions.** This overarching theme applies to numerous proposed requirements, especially flare flow monitoring, flare combustion efficiency reporting, gas composition requirements, liquids unloading, and intermittent-bleed pneumatic devices. The Industry Trades have proposed more efficient and feasible alternatives.

- **EPA has not provided qualitative and quantitative justification to rationalize the proposed requirement to disaggregate current reporting levels in the Onshore Production and Onshore Gathering and Boosting industry segments.** The explicitly references existing definitions of facilities in 40 CFR 98 Subpart W, which includes basin-level reporting for the production and gathering and boosting segments. In this proposed rule, EPA has not clarified how its new proposed level of disaggregated reporting to the site-level results in additional value in understanding the key sources of emissions from a basin. A survey performed by API indicates that the proposed Information Collection Request (ICR) pertaining to the proposed rule significantly underestimates the burden for the impacted sectors that would be required to report individual site level emissions and site IDs. Due to the magnitude of the difference, EPA should provide justification in the form of both qualitative and quantitative results of the costs and benefits of this proposed change and how it aligns with the IRA.

- **Generally, the Industry Trades support the optional use of measured data in addition to EPA or company developed emission factors, when the measured data are appropriate.** Allowing reporters the option to use measured data or emission factors (EPA or company-developed) would increase data accuracy and avoid disincentivizing emission reduction measures. While EPA is increasing the sources for which direct measurement is allowed, there are still some methodologies which only allow the use of prescriptive emission factors and parameters with no alternative options (e.g., flare methane destruction efficiency, fraction of un-combusted gas from engines, crankcase venting). While we support the option to use default emission factors and parameters, requiring reporters to use prescriptive emission factors and parameters in lieu of an option to use directly or representatively measured data disincentivizes deployment of emission reduction measures. Additionally, there are some sources where measured data is required to be used, even if the measured data is infeasible, incomplete or potentially unreliable (e.g., flare flow and composition monitoring, mud degassing methane content). EPA should allow operators to utilize the growing number of technologies with quantification capabilities to report empirical data for source categories covered under Subpart W.

- **Monitoring, measurement or inspection requirements (e.g., flare monitoring, etc.) included in Subpart W should be consistent across other air quality programs.** The Industry Trades are concerned with potentially conflicting monitoring or other compliance requirements between the Greenhouse Gas Reporting Program (GHGRP) and future air quality rulemaking under New Source Performance Standards (NSPS) or other air quality programs under EPA's office of Air and

Radiation. The Industry Trades are recommending that EPA remove prescriptive monitoring, sampling or inspection requirements from the GHGRP and instead reference data made available through requirements in other existing regulations. Furthermore, the Industry Trades suggest that EPA not finalize changes to Subpart W until such time that NSPS OOOOb and EG OOOOc have been finalized, and give another opportunity to provide comments on the proposed updates to Subpart W. It is important to the Industry Trades that there is consistency as opposed to conflicting requirements between the GHGRP and future and current rulemaking under other air quality regulatory programs. Finally, the Industry Trades wish to make clear that monitoring methods should not define emission reporting parameters.

- **EPA should avoid any potential double-counting of emissions across source types. The Industry Trades have identified specific areas with the potential for double-counting.** Since it is expected that the GHGRP will be used to determine associated fees within a methane-fee environment, the Industry Trades are extremely concerned about any source and methodology which could result in double counting emissions, and therefore, double fees. Categories that are particularly susceptible to potential double counting are other large release events and unlit flares; and even between flares and unlit flares, where the proposed Tier 3 destruction efficiency for flares includes unlit flares.
- **EPA must set a period over which submitted GHG reports are considered "final" now that reported emissions will be used as a basis for methane fees.** The Industry Trades are concerned about having to resubmit reports for administrative errors or small corrections in emissions given EPA's historical practice of continually submitting questions regarding previously submitted reports. This would lead to an unworkable situation where additional fees will have to be levied or credited for minor changes in emissions in a methane-fee environment. The Industry Trades recommend a 5% facility-wide reported methane emissions error threshold and only require corrections for emission inventories in the last three full data years.

The following key comments reference specific high priority items that pertain to requirements in the Subpart W proposed rule amendments:

- **EPA's tiered approach to flare "combustion efficiency" is flawed and is not supported by the data cited by EPA in the Technical Support Document.** The Industry Trades are concerned that EPA proposes to override decades of precedent on oil and gas flare monitoring and operation established in federal and state regulations, permits, manufacturer guarantees, and performance tests based on the results of just one limited study. As such, the Industry Trades are requesting EPA to allow performance test data for flare methane destruction efficiency, rather than inappropriate National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements, as aligned with EPA's intent to incorporate empirical data. Further and importantly, the Industry Trades have provided additional data to supplement its position that flare "combustion efficiency" should be a minimum of 95%, or arguably even higher based on data from 132 flares tested in the Permian and Bakken. Please refer to Section 3.8.4.4.
- **EPA's requirement to directly meter or use continuous parametric monitoring to estimate flare volume is technically and economically infeasible, and may actually lead to reporting inaccuracies, especially for low-flow streams.** The Industry Trades propose that EPA allows

reporters the option to continue to use engineering estimates for flare volume. Please refer to Section 3.8.1.

- **There are significant concerns regarding the "other large releases" category relating to third-party reporting, the lack of clarity around what is considered "credible" information, and the thresholds proposed for the source category.** The Industry Trades are concerned that unqualified third-party reports could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear and consistent guidelines across regulatory programs on who would be qualified to provide third-party reports (i.e., the necessary expertise, qualifications, methodology, timeline of sharing detections, etc.). The Industry Trades are also concerned that the use of any credible information may lead to reporters inadvertently using invalid data sources, which can lead to inaccurate emissions and disparity among reporters. Further, EPA's requirement to assume a duration of 182 days if no data is available for the release's start or end date is overly conservative. For these reasons, the Industry Trades request EPA to clearly define the scope of credible information. Further, the thresholds of 100 kg/hr. OR 250 mtCO2e would make events with relatively small durations reportable, which does not appear to be EPA's intent to capture large releases. As such, the Industry Trades request that the thresholds be changed to reflect BOTH a rate and an emissions level per event; at a minimum, the threshold should be changed to '100 kg/hr. AND 250 mtCO2e' (i.e., the 100 kg/hr. rate needs to be paired with a duration of at least 100 hours in order to be equivalent to 250 mtCO2e). Please refer to Section 3.11.1, as well as API's comments in response to Docket ID EPA-HQ-OAR-2021-0317, Section 1 (also included in Annex C of this letter).

- **EPA's assumption that improperly seated thief hatches result in a zero percent control efficiency for controlled tanks is overly conservative and not considered in the TSD. Further, EPA's proposed method to calculate the duration of open thief hatches over-estimates emissions from this source.** The Industry Trades propose that EPA use a bifurcated approach for thief hatches that accounts for when they are fully open or improperly seated, which would have lower expected emissions. Please refer to Section 3.6.2.

- **While the Industry Trades support the flexibility to measure GHG emissions from intermittent bleed pneumatic devices, we request that EPA retain the option to use default population emission factors for sources subject to other regulatory programs.** The Industry Trades do not agree with the requirements to measure and monitor emissions from intermittent bleed devices, especially for sources that will be phased out under the impending methane rules. Please refer to Section 3.1.

- **The Industry Trades request that EPA change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production for consistency and to reflect how the industry owns and operates these facilities**. EPA has incorrectly included centralized production facilities with gathering and boosting, but should instead include them in the production segment where they belong. The Industry Trades also strongly recommend that EPA delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion. Please refer to Section 3.16.

Table of Contents

Docket ID No. EPA-HQ-OAR-2023-0234
October 2, 2023

Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

Docket ID: EPA-HQ-OAR-2023-0234

The comments presented below are arranged by the order of citation in the proposed revisions to the "Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems."

1. Subpart W and the Waste Emissions Charge Program

EPA must present a clear rationale for adding an additional layer to sub-facility-level (i.e., site level) reporting to the onshore production and onshore gathering and boosting segments.

EPA explains in the Proposed Rule that under the current Subpart W, "GHG emissions and activity data are currently generally reported at the basin, county/sub-basin, or unit level, depending upon the specific emission source.[2]" According to EPA, this reporting method "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."[3] To resolve those "challenges," EPA proposes "to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments."[4] Furthermore, EPA proposes to require several new site-specific data elements to be reported, including reporting information for individual well identification numbers, well pad identification numbers, and gathering and boosting site identification numbers.[5] In other words, EPA proposes to require site specific reporting in addition to facility-level aggregate reporting.

EPA correctly explains in the Proposed Rule that "[u]nder CAA section 136, an ''applicable facility'' is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution)."[6] As currently defined for onshore production and gathering and boosting, facilities in these segments are generally defined as the equipment located in a single hydrocarbon basin under common ownership or control. The meaning of the term "applicable facility" is key to implementation of the WEC because the applicability of that program and potential fees are determined on an "applicable facility" basis.[7] In the IRA, the definition of an "applicable facility" in the onshore production and gathering and boosting refers to a facility within the applicable segment, as defined in 40 CFR Part 98 at the time of passage of the bill.

Unless EPA proposes updates to facility definitions in 98.238, reporting should remain at the basin-level. Even if EPA were to propose new facility-level definitions in a future rulemaking, there are remaining concerns discussed below.

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[2] 88 Fed. Reg. at 50309.
[3] *Id*.
[4] *Id*.
[5] *Id.* at 50309-10.
[6] 88 Fed. Reg. at 50285.
[7] CAA § 136(c), (e).

EPA's justification for the proposed sub-facility-level reporting requirements is fundamentally flawed because the Agency wholly fails to consider whether the proposed requirements will be adequate to support applicability and fee determinations under the WEC. As noted above, EPA asserts that the new sub-facility-level reporting requirements are needed because the current Subpart W approach "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."[8] These reasons have nothing to do with the primary purpose of this rulemaking – to satisfy the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.[9] Although not related to the WEC, in EPA's Response to Comments in 2009, EPA agreed that oil and natural gas is to be reported at the "upstream" level because further disaggregation would be burdensome to the reporter.[10]

In fact, nowhere in the Proposed Rule does EPA acknowledge that a key driver (if not the key driver) of the proposal is to generate the facility-specific data needed to implement the WEC, nor does EPA provide any analysis or assessment as to whether the new proposed sub-facility-level reporting requirements will be sufficient for that purpose. Unless corrected in a supplemental proposal, that failure to acknowledge and assess a key factor in the rulemaking will render the final rule arbitrary and capricious. *See*, *e.g.*, *Motor Vehicle Mfrs. Assn. of the United States v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has … entirely failed to consider an important aspect of the problem.") The WEC is based on the existing definitions of facilities subject to Subpart W; for that reason, there is no statutory basis to require reporting on a sub-facility-level basis. Basin-level data satisfies the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.

EPA does not explain how the direction in CAA§136(h) in conjunction with CAA § 114 provides authority for EPA to develop extensive requirements in order to collect empirical data.

The text of CAA §136(h) provides:

> (h) REPORTING.—Not later than 2 years after the date of enactment…the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.

Thus, EPA is charged with updating Subpart W reporting to allow for the use of empirical data in reporting methane emissions that will ultimately become the emissions input to calculating the WEC. EPA does not explain in the Proposed Rule how this new congressional direction, layered on top of CAA § 114, provides authority for EPA to develop extensive requirements for installation of monitoring

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[8] *Id.* at 50309.

[9] CAA § 136(h).

[10] ". . . oil and other petroleum products must be reported by refineries, importers, and exporters under Subpart MM. For the proposed rule, EPA decided to require reporting at these points because reporting at natural gas and oil production wells would have been too burdensome and would have resulted in too many reporting facilities, with no improvement in data accuracy.", https://www.regulations.gov/document/EPA-HQ-OAR-2008-0508-2256.

equipment or sampling to acquire empirical data. In the preamble to this Proposed Rule, EPA failed to discuss its definition of empirical data or its views on what costs for implementation would be reasonable for collecting information under the program. Furthermore, in the discussion of new requirements for individual sources under Subpart W, EPA fails to discuss why individual changes are needed to provide empirical data for the purposes of calculating the methane fee. Before issuing a final rule, EPA must provide a thorough discussion of how this limited change to its statutory authority in the IRA provides a basis for these extensive revisions.

Reporting requirements under Subpart W must be reconsidered in light of the role that Subpart W will play in implementing the Waste Emissions Charge Program.

As noted above, key elements of the Proposed Rule are not adequately explained or supported because EPA failed to assess or explain how the proposed new reporting requirements square with the various elements of the WEC. A fundamental aspect of this issue is the fact that the information generated under Subpart W will be used for wholly different purposes under the WEC than it previously was under Subpart W alone. In particular, the emissions information reported under Subpart W will have new and significant legal ramifications because it will be used to determine the applicability of fee determinations under the WEC. So, Subpart W will be extended from a program that provides emissions data for informational purposes to support the development of the national Greenhouse Gas Inventory by EPA into a program that also serves as the compliance assurance component of the WEC. Simply put, this change in the rule now has financial implications for companies.

That expansion in the basic purpose of Subpart W is highly relevant to the Proposed Rule and in meeting EPA's obligation to revise Subpart W to "allow owners and operators of affected facilities … to demonstrate the extent to which a charge under subsection (c) is owed."[11] For example, as explained above, the extent to which "other large release events" should be reported under Subpart W must be established with an eye toward the relevance of the reported information in assessing the applicability and substantive requirements under the WEC program. The same is true of the other "gaps" in Subpart W that EPA proposes to fill in the Proposed Rule.

The rule must also allow an option to use directly or representatively measured data under all sources to demonstrate reductions in emissions. As proposed, not all source categories allow the use of directly measured data to demonstrate true reductions and improvements (i.e., flare combustion efficiency, crankcase venting, and any other area in the rule where reporters are required to use emission factors instead of having the option to directly measure).

Also, emissions information from oil and gas operations is developed to satisfy a wide range of regulatory and non-regulatory obligations beyond the WEC – including to show compliance with the NSPSs and NESHAPs for such operations and to satisfy emissions reporting obligations (e.g., the SEC's proposed disclosure rule). EPA must clearly specify the information needed to implement the WEC and prevent collateral challenges to WEC compliance based on information generated for other purposes under other regulatory programs.

In short, Subpart W is now unique among the GHGRP subparts in that emissions information submitted under Subpart W will serve regulatory purposes not shared by other industries that report under other

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[11] *Id.*

subparts. As a result, EPA now must consider the implications under the WEC program of all Subpart W requirements and explain how Subpart W and the WEC will be integrated into a consistent, coherent, and workable program. EPA's failure to do so in the Proposed Rule constitutes a failure to consider a highly important aspect of the proposal and prevents interested parties from fully understanding, assessing, and commenting on the proposal.

2. 40 CFR Part 98, Subpart A

2.1 Transferred Assets

A new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of a reporting facility.

The Industry Trades acknowledge that EPA has attempted to address concerns over the requirement for a new owner/operator of a reporting facility to be responsible for historical GHGRP reporting prior to the facility's acquisition date by proposing assignment of a "Historical Reporting Representative."

The Industry Trades reiterate concerns highlighted in our October 6, 2022, letter[12] that a new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of any reporting facility. There are several complicated factors that EPA has not addressed as part of this rulemaking.

Proposing a "Historical Reporting Representative" does not guarantee the accuracy of historically reported information. First, there remains no guarantee that the selected representative would maintain access to the critical data systems used to generate the information used for historical GHG reports; once an acquisition is complete, those historical data systems are often no longer accessible by the purchaser (and in some cases, no longer maintained by the seller). While the "Historical Reporting Representative" could provide some anecdotal context around previously submitted reports, there is no guarantee that the "Historical Reporting Representative" would have had "primary responsibility for obtaining the historical information" which would not meet the threshold required for certification from a Designated Representative.[13] This is particularly true when assets are acquired from economically distressed companies which might no longer have any personnel who were involved in any of the historical GHG reports still on staff.

Furthermore, EPA has requested updates to previously submitted reports dating back 5 years and beyond; in many instances, the requested updates do not impact reported emissions and are often simply requests for clarification on certain reporting elements which are solely administrative in nature (e.g., a rolled up total of "Producing" wells in Table AA.1.ii does not match the count of wells labeled

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[12] API Comments to EPA October 6, 2022. https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0322

[13] 40 CFR 98.4(e)(1): Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

"Producing" in Table AA.1.iii). New owners or operators should not be required to update or submit reports for administrative issues which do not impact reported emissions, and EPA should limit the timeframe under which they request additional information or request re-submittals (see Section 2.2, 'Addressing "Substantive" Errors in a Methane-Fee Environment' below).

Currently within EPA's E-GGRT system, there is no way for a new company to access the reports that were previously submitted by the previous owner. Many times when files are transferred, files are missed or it is not clear what was actually submitted by the company. The new owner may not have access to the previous 5 years of submittals and will likely not have access to all the supporting historical records required to generate the report.

The Industry Trades are recommending that EPA require new owners to be responsible for resubmitting or correcting reports only after the point of acquisition, which is further addressed in the below section, 'Addressing "Substantive" Errors in a Methane-Fee Environment.'

2.2 Addressing "Substantive" Errors in a Methane-Fee Environment

A de-minimis threshold and timeframe must be established for errors to be considered substantive.

The Industry Trades reiterate our October 2022 comment that a threshold must be developed by which an error is to be considered substantive. As currently codified, the definition of "Substantive Error" is overly broad; any change, including those that are administrative in nature that do not impact methane emissions, could trigger a re-submittal. Since it is likely that future rulemaking will result in operators paying a methane fee on emissions, it will become increasingly critical for EPA to:

1. Determine a de-minimis "substantive error" threshold for methane emissions that excludes administrative errors that would result in a re-submittal;
2. Limit the timeframe in which EPA can determine that a "substantive error" has occurred; and
3. Limit EPA's validation of re-submitted reports to only the initial potential error.

As methane fees become associated with submitted reports, it will become extremely burdensome to adjust previously submitted payments for changes in a report which could result in very small financial adjustments. Furthermore, as reported emissions result in more financial impacts, the required levels of burdensome review for a change in reported data will increase, even if a change does not result in a change in emissions. For these reasons, Industry Trades are recommending that EPA develop a de minimis threshold for "substantive errors" of 5% of an applicable facility's reported methane emissions. This 5% de minimis threshold for total GHG emissions is aligned with a level of emissions change that many companies use for updating their corporate emissions due to errors and/or acquisitions/divestitures in accordance with the WRI/WBCSD GHG Protocol. While EPA may not know the scope of a possible error when initially requesting additional information, the reporter should have the option to not re-submit the report if an error is found to be below the de minimis threshold, and operators can provide the supporting information in their response to EPA through E-GGRT.

Finally, the Industry Trades are recommending a limit to the timeframe in which EPA can determine that a substantive error has occurred. The Industry Trades recommend that EPA limit the timeframe in which a "substantive error" can result in a requirement to resubmit a prior year's report to no more than three years, consistent with the record retention requirement in 40 CFR 98.3(g). Further, for re-submittals, EPA should limit the validation to the requested source(s) for which the substantive error was identified. This will avoid the burden of the current practice of EPA re-opening inquiries for other sources that previously have already been addressed by the reporter. This still allows EPA plenty of time for review and questions.

3. 40 CFR Part 98, Subpart W

3.1 Pneumatic Devices

Given the proposed zero-emitting standard in NSPS OOOOb and EG OOOOc, EPA should alleviate the burden with measuring and monitoring emissions across the proposed methodologies from natural gas driven pneumatic controllers during their transitional phase out in upcoming years.

Under NSPS OOOOb and EG OOOOc (§60.5390b and §60.5394c), EPA has proposed a zero-emitting standard for natural gas driven pneumatic controllers that, if finalized as proposed, will result in the elimination of methane venting from natural gas driven pneumatic devices, with the exception of those located in Alaska at a site without power. As part of separate comments on the EPA proposed NSPS OOOOb and EG OOOOc, several of the Industry Trades recommended there be limited exceptions to the zero-emitting standard where not feasible and to use the leak detection and repair program monitoring to confirm proper functioning of pneumatic controllers EPA should consider the requirements and timelines that it is proposing across NSPS OOOOb, EG OOOOc, and Subpart W to promote efficiency across the programs and focus on emission reductions.

Given the potential changes to pneumatics under OOOOb and OOOOc, the time period and practicality of using several of the proposed methods for Subpart W may be minimal. As proposed, Method 1 in §98.233(a)(1) requires installation of permanent flowmeters on equipment that will eventually be removed from service. As proposed, Method 2 would require direct measurements on all natural gas driven pneumatic devices over a several year period that corresponds to expected timelines under NSPS OOOOb and EG OOOOc. Method 2 would require purchasing new measurement equipment and training technicians on their operation, which would have a limited window of use with timelines in NSPS OOOOb and EG OOOOc.

Based on the complexities noted above, Method 3 will likely be utilized by many operators for Subpart W reporting. While the Industry Trades support the intent of proposed Method 3, this option also currently includes undue burden for estimating emissions from devices that will, for the majority, not be in operation within the next decade.

Therefore, the Industry Trades offer the following recommendations, which we describe in more detail in the following comments:

- For natural gas driven pneumatic controllers that are not measured under Method 1 or Method 2 or monitored for proper function under Method 3, EPA should allow the use of the single whole gas population emission factor for intermittent-bleed devices (refer to Section 3.1.1).
- EPA should allow an optional estimation of properly operating intermittent-bleed pneumatic controllers using equipment-specific engineering calculations, or a facility-specific properly operating emission factor based on direct measurement. We elaborate on the details further in Section 3.1.3.
- Amend the proper functioning and malfunctioning emission factors for intermittent-bleed devices to include all relevant studies (refer to Section 3.1.3).

- Allow the duration of an intermittent-bleed device malfunction to be determined by repair date or the last monitoring survey (refer to Section 3.1.4).

Note that both Method 2 and 3 provide time horizons for conducting flow measurements or monitoring surveys up to a 5-year cycle depending on the industry segment in which a facility is located. For both onshore production and gathering and boosting, EPA has proposed that operators measure/monitor approximately the same number of devices each year. This timing directly coincides with the implementation of NSPS OOOOb/EG OOOOc and complicates how an operator might track monitoring or measurement results as equipment changes at a facility. Over time, it may be impossible to monitor the same count year-over-year as the total count of natural gas driven devices will reduce over time.

3.1.1 Retain Whole Gas Emission Factor Approach for Intermittent-Bleed Devices

While operators should have the *option* to measure and monitor emissions from those devices, it should not be *required* for sources expected to be phased out as required in other regulatory programs, as this would result in undue capital investment without creating additional value to stakeholders. The proposed methods are highly inefficient and unnecessary considering the required 15-minute measurement time per device or monitoring each device (i.e., OGI or Method 21 screening) for 2 minutes or until a malfunction is identified. The additional burden is not justified considering:

- Any accuracy gain is expected to be temporary considering that proposed federal air quality rules require all pneumatic devices to be transitioned to zero emitting devices;
- Continuous bleed pneumatic devices, a higher emitting source, are allowed to report using an emission factor approach; and
- It penalizes operators who have invested in cleaner technology by replacing continuous high-bleed controllers with intermittent-bleed devices by requiring them to be measured or monitored.

Therefore, **EPA should retain the option to use the default whole gas population emission factor for intermittent bleed pneumatic devices,** as has been proposed under Method 3 for both continuous high- and low-bleed pneumatic devices. Consistent with the derivations used for new emission factors for high and low bleed continuous pneumatic controllers in Table 5-11 of the Technical Support Document for this Rule, EPA suggests the use of 8.8 scf/hr./device for intermittent bleed pneumatic devices, based on a meta-analysis of a variety of field studies. Moreover, many operators are actively working toward voluntarily eliminating most of these sources as they either fall under current or anticipated upcoming state or federal regulations requiring either source control or a zero emissions standard for this equipment. Implementing a burdensome monitoring program for sources that will soon become less significant doesn't make sense. Operators have collectively performed thousands of retrofits to convert continuous high-bleed pneumatic devices into intermittent bleed devices. Operators who acted swiftly should not face more burdensome greenhouse gas accounting requirements, nor should further near-term retrofits be discouraged by imposing disproportionate accounting burdens.

3.1.2 Method 2 – Suggest Improvement in Measurement Cycle and Alternative Approach

The Industry Trades generally support EPA's Calculation Method 2 to distribute measurement campaigns over multiple years where flow monitors are not permanently installed, with the following amendments:

1) Since the as-proposed NSPS OOOOb and EG OOOOc require phase out of this equipment and numerous operators have been reducing these equipment counts voluntarily, it is not possible to

monitor the same number of controllers each year since equipment counts will be simultaneously declining. Instead, **EPA should require the annual inspections to cover at least 20% of the population of pneumatic controllers at a facility** that have not already been inspected pursuant to Subpart W within the previous 4 years, provided that each device remaining in service at the end of the first five years has received at least one inspection over the five-year period.

2) Additionally, EPA should allow operators to **directly measure a representative sample of pneumatic devices in lieu of the entire population.** This approach ensures accuracy of reported emissions but recognizes the vast geographic dispersion of upstream sites. Additionally, API performed a study on the count of pneumatics at upstream sites and provided that in comments regarding the supplemental OOOOb rulemaking.[14] The time required to drive to each site would be unnecessary when a smaller, representative sample accurately reflects the emissions from these devices. Lastly, this approach is incorporated in several voluntary programs (e.g., OGMP 2.0), retains the accuracy of reported emissions, considers the large geographic dispersion of upstream sites, is consistent with the approach proposed for equipment leaks, improves accuracy over generic emission factor-based estimates, and is more cost effective. The representative emission factor approach would require measurement of a representative sample of pneumatic devices to determine a "facility" specific emission factor.

3.1.3 Method 3 – Suggested Amendments to Improve Intermittent-Bleed Device Monitoring

The Industry Trades also generally support EPA's Calculation Method 3; however, **EPA should amend Calculation Method 3 in three important ways**:

1) **EPA should allow the use of a whole gas emission factor as an option for intermittent-bleed devices,** for the reasons stated in Section 3.1.1**.**
2) **EPA should amend Equation W-1C to more accurately reflect available empirical data on emissions from properly functioning pneumatic controllers**, including a broader suite of field data to improve accuracy. Emission factors should incorporate data from additional relevant studies, [15,16,17] one of which is the API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States," where the data and results have been appended to this letter in Annex A. We encourage EPA to utilize the data from this API study, since the API dataset adds 263 additional measurements of intermittent bleed controllers and cover a wide cross section of the industry sectors (production and gathering and boosting sites)[18]

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[14] https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.

[15] Raw data and linked analyses/reports available at http://dept.ceer.utexas.edu/methane/study/. Accessed September 24, 2023.

[16] David T. Allen, Adam P. Pacsi, David W. Sullivan, Daniel Zavala-Araiza, Matthew Harrison, Kindal Keen, Matthew P. Fraser, A. Daniel Hill, Robert F. Sawyer, and John H. Seinfeld. *Environmental Science & Technology* 2015 *49* (1), 633-640. DOI: 10.1021/es5040156

[17] API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States" attached in Annex A and data provided by attachment as an Excel file within this docket.

[18] Note that EPA's comment in the TSD regarding being near or below the OGI threshold for properly functioning controllers using the API field study's emission factor would be resolved by combining the Zimmerle, API, and other relevant datasets to derive properly functioning and malfunctioning emission factors as shown below in Revised Eq. W-1C (the proposed properly functioning emission factor of 0.9 scf/hr/device is equivalent to ~17 g/hr, which is

while the Zimmerle *et al* study only evaluated sites with compression; thus, the resulting bifurcated emission factors would be more accurate and representative. Specifically, **the Industry Trades recommend revision of Eq. W-1C:**[19]

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{\mathbf{20.0} \times T_{mal,z} + \mathbf{0.9} \times (T_{t,z} - T_{mal,z})\} + (\mathbf{0.9} \times Count \times T_{avg})\right] \quad (Rev.Eq.W-1C)$$

Where:

20.0 = Whole gas emission factor for properly functioning intermittent-bleed controllers, scf/hr.

0.9 = Whole gas emission factor for malfunctioning intermittent-bleed controllers, scf/hr.

3) **EPA should allow for the optional estimation of properly operating pneumatic controllers based on equipment specific engineering calculations**, which can be accurately assessed with piping volume, manufacturer actuation data, and average actuation frequency,[20] **or the development of a facility specific properly operating emission factor through direct measurement** of a representative sample of devices across a facility.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{16.1 \times T_{mal,z} + EF_z \times (T_{t,z} - T_{mal,z})\} + \sum_{y=1}^{y}\{EF_y \times T_{t,y}\}\right]$$

Where:

z = Count of intermittent bleed pneumatic devices that malfunctioned during the reporting period,

y = Count of intermittent pneumatic devices that properly operated over the entire duration of the reporting period, and

EF = Properly operating emission factor for the specific device or facility.

3.1.4 Intermittent-Bleed Device Survey Improvements

The duration of an intermittent bleed device malfunction should be determined by repair date or other detection approaches, in addition to traditional survey repair verifications.

Operators will have a clear indicator that a malfunctioning device has been returned to properly operating condition based upon the repair date or other detection approaches. EPA should allow for such information to be used for the time input into the malfunctioning controller emission estimation equation, which aligns with EPA's efforts to increase the quality / accuracy of the reported data. For

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above the OGI detection limit). EPA also speculates in the TSD that the API field study included many zero emitting measurements due to the short measurement duration. However, as discussed in the attached paper (see Annex A, pp. 4), the measured emission data points that were below half the effective resolution were conservatively assumed to be half the effective resolution for the minimum instantaneous emission rate in all the analyses. Further, the Allen *et al* 2014 paper conducted a sensitivity analysis which showed that actuations that were just missed by the measurement timeline at 15 minutes had a very small effect on the overall population emission factor estimate.

[19] See Annex F Analysis to support amendment to Calculation 3 for Intermittent Bleed Devices.

[20] https://ogmpartnership.com/wp-content/uploads/2023/02/Pneumatics-TGD-SG-approved.pdf.

example, while conducting AVO inspections, operators can detect that an intermittent device is continuously venting by feeling the gas exit port.

The Industry Trades also support EPA's proposal to retain the option for an operator to apply engineering estimates to determine the time in which the device was in service, in lieu of the default 8760 hours.

Intermittent bleed device surveys should include additional flexibility by allowing audio, visual, and olfactory (AVO) inspections.

Operators should be able to take credit for any surveys, provided those surveys satisfy the intent of the rule. Based on the proposed rule for NSPS OOOOb, facilities subject to NSPS OOOOb monitoring would be required to use non-emitting pneumatic devices. Some facilities that are not subject to NSPS OOOOb may conduct LDAR for state, federal, or voluntary programs and may wish to screen pneumatic controllers while on-site and use that empirical observation of properly functioning or malfunctioning for GHGRP reporting.

While many of these regulatory programs would meet the technology options provided in 98.234(a) for use in monitoring properly functioning pneumatic devices, additional flexibility should be incorporated by allowing the use of AVO. AVO is appropriate because AVO inspections can be used to detect that an intermittent device is continuously venting through feeling the gas exit port, as previously stated.

3.1.5 EPA Has Underestimated the Cost of Direct Measurement for Pneumatic Devices

Oil and gas companies do not currently own or have training to conduct direct measurement of pneumatic devices. EPA included no additional cost for purchasing the high flow sampling equipment, staff or training on the equipment. With the large number of operators having to acquire this data at the same time, new equipment must be first manufactured and then purchased by these operators to do this work concurrently. EPA added no additional labor impact; it will require significantly more staff to conduct the measurements. The company will need to hire staff, as additional staff will be needed to conduct these measurements that require 15 minutes per measurement minimum over a range of device counts per facility depending on whether it is a gas or oil well, number of wells, and the equipment required for production. It will likely not be possible to cover 5-10 sites per day, considering repairs will likely be performed at the same time and many sites and pneumatic devices will be spread out over long distances. Furthermore, operators will need to be trained to use high flow samplers as this equipment is currently not used in the oil and gas industry. None of these additional costs have been addressed in the Regulatory Impact Analysis. EPA claimed all this could be done with only an additional $600,714 in cost which would not be sufficient to cover the cost for a medium sized operator.

3.2 Acid Gas Removal and Nitrogen Removal Units

3.2.1 Proposed Methods for Methane Emissions

The proposed mass balance approach for quantifying emissions will not lead to accurate reporting for methane emissions, and sour gas sampling poses a significant safety concern.

EPA proposes to report methane along with CO_2 from Acid Gas Removal Units (AGRUs) and Nitrogen Removal Units (NRUs). The Industry Trades believe that the proposed methodology in Equation W-4C (a mass balance approach) will not lead to accurate reporting for methane emissions. Since the solubility of methane in amine is very low, the difference in methane concentration in the inlet and outlet processed gas stream will be negligible. Therefore, the ability to discern a difference in inlet versus outlet methane composition will make it difficult (if not impossible) to accurately determine methane emissions using a mass balance approach. Further, sampling the high-pressure acid gas stream at the inlet of the AGRU contactor poses a significant safety concern (see next comment). For these reasons, the Industry Trades recommend removing this methodology for methane emissions reporting.

EPA is proposing a requirement to perform direct sampling of gas streams into these units at least annually. The Industry Trades remind EPA that these streams can also contain dangerous levels of hydrogen sulfide (H_2S), and any work near or around these units that is not necessary for the optimal function of the equipment should be limited to protect the personnel responsible for performing these tasks. The Industry Trades recommend removing the prescriptive sampling requirements for these streams and allow reporters to use representative samples or direct site-specific samples if deemed to be appropriate.

For the simulation method (Method 4), the Industry Trades recommend that EPA clarify that representative measurements can be one time, annual or a more frequent measurement as deemed appropriate for the facility's operation.

3.2.2 Reporting Requirements for AGRUs and NRUs

Some of the proposed reporting requirements for AGRUs and NRUs are duplicative and unnecessary, so should be removed.

EPA proposes that those operators sending gas from an AGRU or NRU to a control device also report associated details regarding the combustion device (flare ID, gas flow rate, etc.). Requiring this information to be reported on this tab of the Subpart W reporting form could cause duplicative reporting with sources on other tabs (e.g., flares), and is ultimately not relevant to reporting by itself. The Industry Trades recommend removing this requirement. Reporting this level of detail is also inconsistent with EPA's 2022 proposed revisions, which greatly streamlined the reporting requirements for flares.

EPA is proposing to include solvent type in data reporting; the Industry Trades does not believe this information to be beneficial or helpful in validating the reported information, and EPA did not address why this element is to be reported in the TSD. The Industry Trades recommend that the EPA remove this unnecessary reporting requirement.

Finally, the Industry Trades request clarity from EPA around reporting activities such as acid gas injection through Subparts W, PP and UU. The proposed requirement to report CO_2 sent offsite under Subpart PP is duplicative of CO_2 supplier reporting. Regarding the WEC, it will be absolutely critical that industry has a clear understanding of exactly how emissions are to be accounted for between these subparts without over-reporting, double counting, or allowing some operators to not report under these subparts at all (creating an economic disadvantage as it is unclear how some activities which result in producing CO_2 are to be accounted for in the various rules).

3.3 Dehydrators

3.3.1 Desiccant Dehydrators

Reporting requirements for desiccant dehydrators should be streamlined for a source type that is not a significant contributor to GHG emissions.

In the late-2022 proposed changes, EPA appeared to be moving away from requiring detailed information reported for desiccant dehydrators; however, in the current proposal (August 1st, 2023), EPA is requiring more reporting details. Emissions from desiccant dehydrators are periodic and can be very infrequent in nature. The Industry Trades support reducing the overall reporting requirements on these units as they are not significant contributors to annual GHG emissions.

Molecular sieve dehydrator emissions are expected to be extremely infrequent (i.e., once every 5-10 years), and should be categorized as blowdown emissions.

EPA is also proposing to add molecular sieve units to the desiccant dehydrator category. Molecular sieves are closed systems with no emissions to the atmosphere, except when the desiccant must be changed which is infrequent; typically, only once every 5-10 years. Furthermore, emissions from opening a molecular sieve dehydrator would be an activity considered by most operators to be a blowdown event – and should be accounted for under the blowdown category rather than under dehydrators. Categorizing molecular sieves under the desiccant dehydrator category not only raises confusion but could potentially result in double counting of the blowdown emissions.

3.3.2 Proposed Measurement Data

The proposed measurement requirements are burdensome and will not increase the accuracy of the emissions estimates; therefore, engineering estimates for parameters should be allowed.

EPA is proposing to require direct measurement of some parameters for large dehydrators. Specifically, EPA is proposing to require direct measurement of the feed natural gas flow rate, feed natural gas water content, and wet natural gas temperature and pressure at the absorber inlet. The Industry Trades do not believe that direct measurement of these parameters is appropriate nor that it would result in more accurately reported emissions. Sampling the feed natural gas water content, gas temperature and pressure will provide an instantaneous snapshot view of the operational conditions of a unit that operates year-round, and in potentially varying operating conditions, during which these parameters may shift.

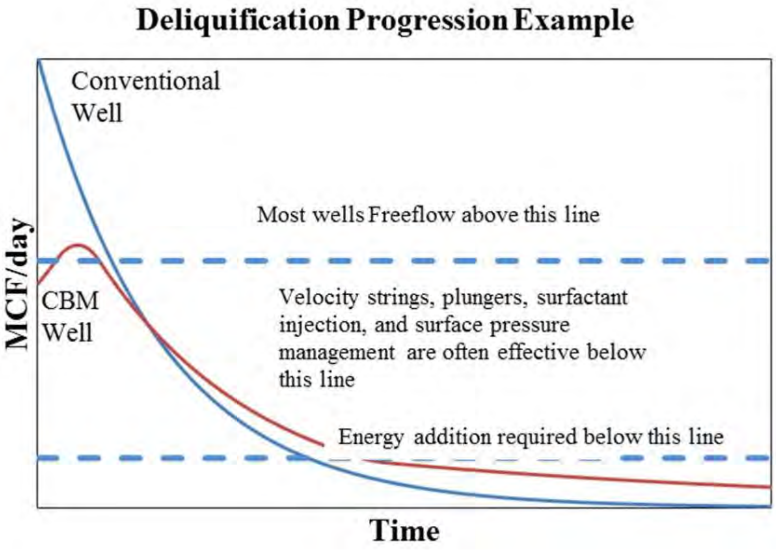
In some instances, facilities are not equipped with a meter upstream of the dehydration unit; instead, the gas is measured at the outlet of the facility. As a result, collecting direct measurement of feed natural gas flowrate will require extensive modifications without increasing the quality of the reported data. Dehydrator emissions are not directly proportional to natural gas throughput; in other words, the inlet gas rate to the dehydrator alone does not correlate with dehydrator emissions. Instead, glycol recirculation pump rate, configuration (e.g., flash tank separator, stripping gas) and operating pressures do impact emissions, and are known by operations in order to maintain optimum operating conditions. Requiring operators to install, calibrate and maintain meters at the inlet to the dehydrators would be costly while not addressing the accuracy of the elements that do meaningfully impact actual emissions. Therefore, the Industry Trades request that engineering estimates of the parameters used in the simulation software continue to be included as an option, especially considering the parameters represent annual averages.

3.4 Well Venting for Liquids Unloading

EPA should not require flow meter measurements of liquids unloading venting under Calculation Method 1 as it is technically and economically infeasible.

The proposed rule language that requires Calculation Method 1 every three years is unnecessary and burdensome and will not lead to more accurate reporting. EPA states in the preamble that this requirement will 'ensure that the engineering equations accurately and consistently represent the quantity of emissions from unloading event.' EPA must justify this additional burden and how potential differences between method results will be treated, as repeated validation of the methods will not lead to more accurate reporting. Further, EPA did not consider the Allen *et al* 2015 study that directly measured emissions from liquids unloading.[21]

Which wells will require and how often they require liquids unloading venting is not predictable or consistent. Liquids unloading or deliquification is the process of removing liquids build-up in a gas well. Not all deliquification techniques result in venting. Most wells in the US do not vent to the atmosphere. Managing well bore liquids build-up in gas wells is required to maintain production, avoid early abandonment of the wells, and maximize resource recovery. Liquids build up in the well when the velocity of the production string is not sufficient to push the liquids up the well bore. The deliquification approaches change as a well moves through its lifecycle, as shown in the figure below. Manually opening a well to atmosphere to reduce the back pressure on the liquids column results in most of the liquids unloading venting. When this is needed is variable and does not necessarily occur every 3 years.



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[21] https://pubs.acs.org/doi/10.1021/es504016r.

Adding a flow meter will put back pressure on the well, restricting flow and preventing the well from unloading or making it more difficult. The purpose of liquids unloading is to relieve the back pressure on the well so that the well is able to push liquids, and a flow meter would prevent this from occurring. Anecdotal evidence from one operator that currently unloads gas wells in Colorado has trialed measurement on liquids unloading on twelve wells indicating this. The operator found results similar to the current GHGRP calculations. Additionally, the operator found that to use a meter, the gas must be routed through a knockout or other vessel that may have small piping between it and the meter. The constriction made the unloads take longer and reduced the effectiveness of the unloads. Of the twelve trial measurements, not a single well successfully unloaded itself.

The volume of gas, and associated GHG emissions, is relatively low and therefore does not warrant the additional expense and effort of measurement. In fact, the total emissions reported in 2021 for all operators was a very small percentage of overall methane emissions from onshore production.

Measuring the small volume will be extremely challenging and likely require a costly ultrasonic meter (please see the flow meter challenges discussed in more detail in Section 3.8.13.8.1 of the comments). The measurements will be challenging to obtain, as they are short duration and turbulent flow; therefore, the low flow is unlikely to be measured by a flow meter.

The rule does not account for all the added costs of a flow meter that will likely not be capable of measuring the small volume of the gas. These costs include:

- The flow meter(s)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofit the line to add a flow meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expanding or adding the remote transmitting unit
- Calibration and maintenance of the flow meter
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

Additionally, EPA does not require operators under NSPS OOOOb to install a flow meter for liquids unloading venting. NSPS OOOOb does not prescribe these flow meter requirements as necessary to achieve the zero-emission limit for liquids unloading, or for the recordkeeping/reporting requirements for these events, so it is unclear why this would be required under Subpart W.

Furthermore, a meter could be installed on a well that had liquids unloading venting in a previous year and never does again, or not be installed on a well that suddenly requires liquids unloading venting.

Industry should be allowed to continue to use the liquid unloading engineering estimates or other engineering process knowledge to estimate the duration and volume of emissions as measurement will not result in more accurate estimates.

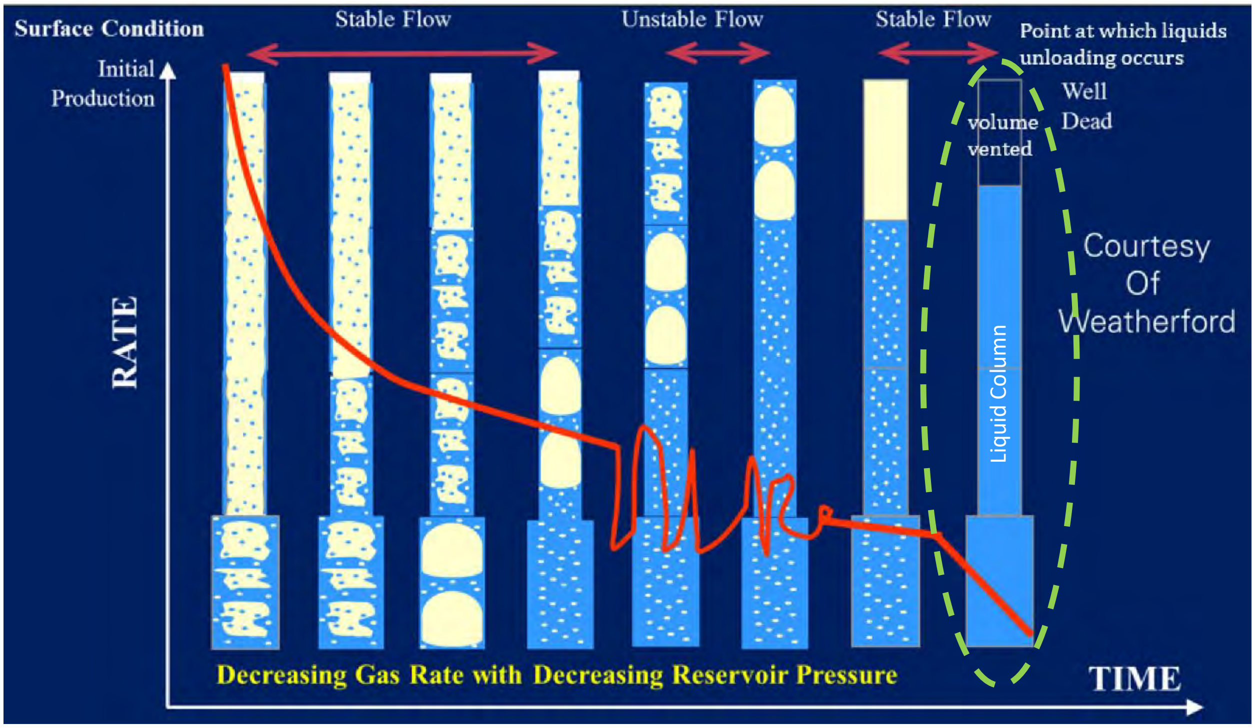
Additional suggested revisions will improve the clarity of the requirements for reporters.

EPA should clarify that liquids unloading only applies to gas wells as was done in NSPS OOOOb. Oil wells typically require artificial lift to produce the liquids and do not vent gas.

The Industry Trades support proposed revisions to add reporting requirements for liquids unloading events which vent directly to atmosphere or are routed to a control device, including whether the unloading event is automatic or manual, specific flow-line and tubing depth data, and the hours that wells are left open during unloading events. However, EPA should clarify that reporting for unloading events should only apply when the gas is vented directly to the atmosphere or routed to a control device. These additions will improve clarity for reporters and provide greater context for the reported emissions for EPA.

Additionally, EPA should consider revising the definition of CDp in Equation W-8 to Idp (Internal Diameter) to allow the application of either tubing diameter if the well is equipped with tubing string and no plunger lift, or casing diameter if the well does not have tubing and plunger lift. It is common practice for operators to first install a tubing string to increase flow velocity and install a plunger lift later when the well undergoes production decline. The diameter that is used in the equation should be the diameter of the portion of the well that is vented, whether venting the casing, tubing, or both. EPA should also clarify that the depth is based only on the vertical depth for horizontal wells.

Furthermore, the volume should be able to account for the fluid column depth. EPA should allow companies to determine the depth to the top of the fluid and exclude the remaining volume from the venting volume estimate. The reason for liquids unloading is to remove the liquid column from the well. The volume of liquid should not be considered gas that is vented, and rather only the depth above the fluids should be used to quantify the vented gas, as shown by the 'volume vented' in the following diagram.



3.5 Blowdowns

Streamline blowdown reporting to reduce the burden without affecting accuracy.

EPA is proposing to require site-level details regarding blowdowns. The Industry Trades recommend streamlining this source category by allowing reporters to aggregate events by type at each facility. Aggregating events by type would avoid line-by-line reporting per event and greatly reduce the complexity of reporting for the source category, without impacting data quality or transparency. For example, EPA should allow blowdown emissions to be reported by site, but aggregated by activity (i.e., all blowdown types would be reported in aggregate rather than line-by-line for each blowdown event).

For mid-field pipeline blowdowns not associated with a given well pad or gathering station, reporting a site could be challenging. The Industry Trades recommend allowing these types of blowdown events to be aggregated by county (without segment ID), which is consistent with other pipeline reporting under the current rules for Pipeline and Hazardous Materials Safety Administration (PHMSA).

As discussed in the 'Other Large Release Events' comments, there is a significant probability of double counting between blowdowns and 'Other Large Release Events' due to the low emission rate threshold proposed for the 'other large release events' source.

The Industry Trades are also concerned that, due to the low hourly emission rate threshold specified by EPA for the "Other Large Release Events" category, these events could be inadvertently counted in both this blowdown category as well as "Other Large Release Events" - resulting in significant double counting. EPA should clarify that any emission event that triggers the "Other Large Release Events" threshold but belongs under a reportable emissions source category (e.g., blowdowns) should be reported within its associated source category, not under "Other Large Release Events." The Industry Trades have elaborated on this point in the "Other Large Release Events" section of this letter.

3.6 Storage Tanks

3.6.1 Produced Water Tanks

Requiring estimation of emissions from produced water tanks is burdensome and unnecessary due to the low expected emissions of methane based on solubility limits.

Methane emissions from produced water tanks are expected to be low due to solubility limitations of methane in water. A study conducted by Idaho State University[22] to quantify the solubility of methane in produced water found that the solubility of methane was in a range between 1 and 12 scf/barrel at pressures ranging from around 100 to 2,000 psi and temperatures ranging from 200 to 300°F. While the study did not publish results for lower temperature ranges, the authors state that the solubility decreases with decreasing temperature and/or pressure. The solubility of methane in produced water is also expected to be lower in the presence of other hydrocarbon gases, such as ethane, per the study authors. The Idaho State University methane solubility study results are aligned with the produced water emission factors published in the 2021 API Compendium (Table 6-26): the Idaho State University study value at around 1000 psi, 200°F and 13 % salinity (4.2 scf/bbl.) equates to around 0.08 tonne CH_4/1,000 bbl which compares to 0.0536 tonne CH_4/1,000 bbl (at 1000 psi, 10% salinity) from Table 6-26 of the API Compendium. Since the methane emissions from a produced water tank would be lower than the

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[22] Blount, C. *et al*, *Solubility of Methane in Water Under Natural Conditions*, Idaho State University Department of Geology, June 1982, https://www.osti.gov/servlets/purl/5281520.

solubility limit (i.e., emissions are based on the partial pressure of methane in the tank headspace, which is lowered when other hydrocarbons are present), the Idaho State University study corroborates the API Compendium emission factors for produced water tanks.

If EPA opts to keep produced water tanks in the GHGRP, the Industry Trades recommend allowing operators to assume that water tanks contain 1% of the oil content. Texas Commission on Environmental Quality (TCEQ) Emissions Representation for Produced Water guidance[23] describes that oil or condensate floats on top of the water phase and contributes to the partial pressure within the tank. The Industry Trades recommend that EPA allow operators to assume that 1% of the oil content is in the produced water tanks which is a conservative estimation given that the guidance is intended to capture VOC emissions, and it is unlikely (as described above) that significant methane remains in the produced water.

The Industry Trades note that EPA provides a stuck dump valve emission factor for water tanks if method 1 or 2 is used, but no factor is provided for tanks using method 3.

3.6.2 Thief Hatches

EPA should allow improperly seated thief hatches to be treated as an “other” component under equipment leaks. The proposed capture efficiency of zero percent for storage tanks with an improperly seated thief hatch is inaccurate and would significantly overestimate emissions.

EPA has proposed a 100 percent reduction in VRU capture efficiency and flare destruction efficiency for both hydrocarbon and produced water storage tanks with open and improperly seated thief hatches. This proposed reduction in capture efficiency is inaccurate and would significantly overestimate methane emissions. The Industry Trades propose a bifurcated approach to reporting emissions from thief hatches where improperly seated thief hatches would be treated as a fugitive emission reported under equipment leaks, and open thief hatches would result in a zero percent capture efficiency for control devices.

Thief hatches are safety devices that relieve positive and negative pressure in atmospheric storage tanks to prevent structural damage. Thief hatches accomplish this by using weights or springs that allow the thief hatch valve to open at given pressure and vacuum settings. The thief hatch valve then reseats after the tank pressure or vacuum has dissipated. Thief hatch valves are designed to seat with minimal leakage under their pressure setting. For example, Enardo 660s, a common thief hatch in the upstream oil and gas industry, conforms to API 2000 Venting Atmospheric and Low-Pressure Storage Tanks Standard to not leak more than 5 SCFH at 75-90% of the thief hatch valve’s pressure setpoint. Many of Enardo’s valves can achieve smaller leak rates at 90% of the pressure setpoint. LaMot’s L12 series thief hatches, another common type found at upstream oil and gas facilities, will not leak more than 1 SCFH at 90% of the pressure setpoint. These leak rates are a fraction of the gas produced in tanks. For example, the reduction in capture efficiency ranges from 0.5% to 2.5% given these leak rates for tanks with a relatively small throughput of 100 bbl./day and average GOR of 48 scfs/bbl given the above leak rates. Improperly seated thief hatches are technically closed but leak around the seat due to either grime on the valve gasket or an inadequate seal, similar to valves that leak into open-ended lines. Improperly seated thief hatches do not result in a zero percent capture efficiency because they are still able to

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[23] produced-water.pdf (texas.gov).

maintain positive pressure on the tanks, allowing gases to be routed to the control device. The leakage from an improperly seated thief hatch is significantly lower than from a partially open thief hatch.

EPA's proposal to assume zero percent capture efficiency from improperly seated thief hatches that are leaking as opposed to venting gas will grossly overstate methane emissions. Instead, the Industry Trades propose that improperly seated thief hatches be considered and reported as a fugitive emissions component (under the "other" fugitive component category).

A zero percent capture efficiency as proposed by EPA would be used for thief hatches that are observed above their setpoint using pressure transmitters and confirmed open or found open during inspections. The Industry Trades believe that this bifurcated approach of accounting for improperly seated thief hatches as equipment leaks, and assuming open thief hatches result in a zero percent capture efficiency would be a more accurate representation of emissions from thief hatches.

EPA should allow engineering estimates of the open thief hatch volumetric flow for tank batteries with a common vent line.

For many tank batteries, vent lines for multiple tanks are combined in a common vent line header that is routed to a control device. If one thief hatch is found open, the entire tank battery should not be assumed to have open thief hatches with a resultant zero percent capture efficiency. The Industry Trades suggest that EPA allow for use of engineering estimates, e.g., modeled volumes, in this case to report the emissions from the tank battery's open thief hatch.

EPA should allow other monitoring options to detect open thief hatches besides thief hatch sensors and visual inspections as visual inspections create significant safety concerns. The start date for an open thief hatch should be based on best available monitoring data.

EPA proposes thief hatch sensors or visual inspections as the monitoring options for detecting open thief hatches on controlled storage tanks. The Industry Trades recommend that EPA allows Tank Emission Monitoring Systems (TEMS) or other parametric monitoring in addition to thief hatch sensors. For example, many companies utilize a pressure transmitter or similar device to determine if a thief hatch is venting as they are more accurate.

Similarly, EPA should expand the visual inspections to allow other monitoring techniques (audio and olfactory in addition to visual, OGI, and alternative screening technology) due to potential safety issues with a strictly visual inspection of thief hatches. Since thief hatches are located on the top of the tanks, a visual inspection may require personnel to climb to the top of the tanks with potential vapor exposure (e.g., H_2S). Therefore, more remote monitoring techniques should be allowed to monitor for open thief hatches on controlled tanks.

Thief hatch sensors do periodically malfunction and may falsely indicate an open thief hatch. As such, EPA should allow reporters to exclude thief hatch sensor malfunction periods and instead use best available monitoring data (e.g., TEMS, other parametric monitoring, last inspection) when determining the time that the thief hatch was open in calculating and reporting storage tank emissions.

EPA is proposing that an open thief hatch without a thief hatch sensor is to be considered open since the last required inspection, which is proposed at least annually or more frequently if subject to AVO surveys under NSPS OOOOb or EG OOOOc. The Industry Trades recommend that EPA allow an operator to assume the thief hatch has been open since the last credible inspection (e.g., routine operator inspection) and not solely based on the last required thief hatch inspection. Proposed NSPS OOOOb and EG OOOOc (and earlier versions of the NSPS) do not require thief hatch sensors but instead require routine inspections of closed vent systems and covers for applicable storage vessels in addition to routine site surveys of fugitive emissions components. These inspections and additional monitoring would offer more frequent opportunities for operators to identify open thief hatches on a routine basis.

Emissions from an open thief hatch should be reported for the year in which it was discovered.

EPA is also seeking comment on expanding the start date of the open thief hatch prior to the beginning of the reporting year. The Industry Trades suggest that the reporting for an open thief hatch be limited to the calendar year in which the open thief hatch is discovered. If the thief hatch is open over a period that started prior to the start of the reporting year, then the total duration should be reported in the year in which it was discovered to avoid re-submittal of prior year reports. To expand on this point, the Industry Trades propose that any episodic GHG emissions be reported solely in the reporting year in which it was discovered.

3.6.3 Atmospheric Storage Tank Exclusions

The Industry Trades recommend that emergency use storage tanks and process tanks not be subject to reporting.

The Industry Trades also recommend that EPA specify that some tanks are not subject to reporting under this program. Some facilities contain tanks which are used only rarely for off spec oil and should be excluded from the definition of storage vessel. These process vessels are rated significantly higher than atmospheric and do not have similar venting risks as atmospheric storage tanks. The expected GHG emissions from these emergency use storage tanks would be minimal. At the state level, emergency use tanks are exempt from control requirements from state and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.[24,25]

Likewise, process tanks like those that recirculate liquids for processing should also be excluded. Storage tank regulations, including proposed NSPS OOOOb and EG OOOOc, have historically excluded process vessels or tanks. In short, any tank which is not expressly used as a primary storage vessel for hydrocarbon liquids and produced water (if included as proposed) in the normal operation of a production or gathering and boosting facility should be excluded. Therefore, the Industry Trades offer the following redline of the proposed definition of atmospheric pressure storage tank:

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[24] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[25] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

> *Atmospheric pressure storage tank means a vessel ~~(excluding sumps)~~ operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of nonearthen materials (e.g., wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof. For the purposes of this subpart, the following are not considered atmospheric pressure storage tanks:*
>
> - *Sumps;*
> - *Process vessels such as surge control vessels, bottoms receivers or knockout vessels; and*
> - *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

3.6.4 Gas-liquid Separator Liquid Dump Valves

The start date for a stuck separator dump valve should be based on best available monitoring data.

Like the above comment on open thief hatch monitoring, EPA should allow the start date for a stuck gas-liquid separator liquid dump valve to be based on the best monitoring data available (TEMS, other parametric monitoring, alternative screening technology, routine operator inspections, etc.) rather than solely the date of the last required annual visual dump valve inspection. This flexibility will allow operators to calculate storage tank emissions more accurately.

3.6.5 Addressing EPA's Request for Comments

Industry Trades recommend adding GOR analyses as an allowable calculation methodology.

EPA is seeking comments on whether adding a laboratory measurement of the GOR from a pressurized liquid sample is an appropriate calculation methodology for atmospheric storage tanks. The Industry Trades are supportive of adding this GOR method to calculate emissions from storage tanks and emphasize that these samples do not need to be taken on a site-by-site basis to be representative.

3.7 Associated Gas Venting and Flaring

EPA is proposing to require reporting of associated gas venting and flaring on a site-by-site basis. The Industry Trades recommend that EPA keep emissions and associated data rolled up to the basin-level (or county-level, as required by other regulatory programs, such as PHMSA).

EPA is seeking comment on whether to continue to require reporting of GOR, produced oil volume, gas to sales volume, etc. The Industry Trades are in support of no longer requiring these reporting elements, unless required by the WEC. In general, the Industry Trades support efforts to streamline the data reporting process, particularly when the reported elements are not used to calculate emissions.

3.8 Flares

It is critical to the Industry Trades that the GHGRP does not directly include monitoring, measuring and sampling requirements for flares in order to avoid conflicting or duplicative requirements. Instead, the GHGRP should refer to data available through other applicable federal air quality regulatory programs. The Industry Trades request that EPA should ensure consistency across programs. This will help ensure that the requirements in the GHGRP are fully harmonized with any potential requirements under other federal air quality programs.

The Industry Trades support more accurate approaches for destruction efficiency for estimating flare emissions; however, the **tiers as proposed should be amended** (specific comments below). Further, while it is sensible to allow for the use of available empirical data and appropriate to define multiple estimation methods based on different types of available information, **monitoring requirements that are repeated in Subpart W rather than referencing the applicable regulation, especially those that exceed NSPS OOOOb and EG OOOOc requirements, which are defined in those rules, should not be included in Subpart W**. Further, flare estimating methods should be appropriate to the equipment and designs deployed within the segment (e.g., small, mostly unassisted, distributed flares) rather than arbitrarily under a rubric designed for a specific compliance assurance matter from a very different set of facilities and designs (refining and chemical manufacturing). Finally, flared emissions should be reported at the facility level rather than at the individual well pad or site, and especially not with attribution to the flare gas source.

With the Industry Trade's recommendations, the Industry Trades generally support EPA's focus on pilot flame monitoring as unlit flares can be large sources of methane emissions from flares. However, the proposed rule's requirements to continuously measure or monitor flow volumes, as well as use continuous gas analyzers or pull quarterly samples for gas compositions would result in little benefit to accuracy while posing significant costs and safety risks. Further, the Industry Trades disagree with EPA's proposed three-tier destruction efficiency (see Comment under Section 3.8.4 below).

3.8.1 Flow Measurement

3.8.1.1 EPA Should Continue to Allow Process Simulation and Engineering Calculations for Flare Flow Volumes

The Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices. The proposed flare metering requirements are infeasible, burdensome and may lead to inaccuracies for most flares in production and gathering and boosting operations. Furthermore, EPA did not address the need to measure flare flow in the proposed rule's TSD. Likewise, the proposed parametric monitoring does not provide a more accurate or cost-effective alternative to metering. **EPA should retain the current Subpart W language stating that, "…If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data."[26]**

Proposed Flare Measurement Methods are Inaccurate and Infeasible for Low Pressure Flares

The proposed flare flow measurement methods are inaccurate, as well as infeasible, for low pressure flares in production and gathering and boosting operations.

The primary streams that are routed to flare at typical oil and gas facilities include:

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[26] Current § 98.233(n)(1)

- Low-flow pilot, purge, sweep, and/or auxiliary gas used to ensure flares are lit, operating safely, and have optimal destruction efficiencies;
- Low- pressure gas that is intermittent and turbulent from tank flashing, working, and breathing losses;
- Mid- pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales that has intermittent and turbulent flow; and
- High pressure separator gas flaring in areas with stranded gas pipeline take-away loss that has intermittent flow and is decreasing across the country.

Most meters are unable to accurately measure the flow of low-volume, low-pressure, intermittent, and turbulent streams.

In addition to the concerns surrounding the metering of each individual stream, the Industry Trades are concerned with EPA's application of flow meters or parametric monitoring across every upstream application. EPA's requirement to use continuous flow measurement devices or parametric monitoring for low-pressure flares and purge/sweep/auxiliary gas streams is technically infeasible. Meters require steady pressure and flow to accurately measure flow rates. Most meters are unable to accurately measure low pressure and flow conditions found in purge/sweep/auxiliary gas and storage tank streams, or variable flows affecting several streams, such as tanks due to production slugs or when separators dump fluids, sporadic flaring of associated natural gas, and high-pressure equipment blowdowns. Furthermore, the flare volumes rapidly decline from the initial production of the well and become more sporadic. Metering the scenarios described is challenging, and industry needs a flexible array of options to ensure proper combustion and accurate reporting. The incorrect application of meters or parametric monitoring devices can lead to inaccurate flare volumes relative to using process simulations, engineering estimates, and indirect measurement allowed under the current rule. **The Industry Trades recommend the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.** The industry utilizes reliable process simulation and engineering calculations which are often more accurate than metering low pressure, low flow, and highly variable streams within the upstream oil and gas industry. The Agency and industry rely on process simulation and engineering calculations in permitting, designing and maintaining facilities for safety and environmental reasons, and have made great strides in the accuracy of these approaches in recent decades. Additionally, the GHGRP allows process simulation to estimate composition and volume of gas for emissions (e.g., tank flash gas, dehydrators, etc.) that are not going to flare so the same methods should be allowed for gas streams that do go to flare. As such, it does not make sense to expend significant capital and operational resources to install continuous monitoring when engineering estimates are more reliable and allowed for uncontrolled sources (e.g., storage tank vents and dehydrators). Interestingly, EPA couples burdensome, although potentially less accurate, measurement technology for flow with default destruction efficiencies, without allowance for measurement or performance test data; this would negate any possible improvements in flare emissions accuracy.

In Colorado, the Air Pollution Control Division (APCD) recognized that flow meters have low accuracy at low vapor volumes by first approving a variance in 2022 to their flow meter requirements and more recently amending their Regulation 7 rule language in 2023 to include pressure actuators as an alternative to flow meters. Pressure actuators are an example of a solution implemented to ensure combustion. For reporting purposes, engineering estimates and simulation software based on site specific information (e.g., GOR and liquid throughput) are more accurate to generate emissions reporting information for flares in the production and gathering and boosting operations. It is important that the EPA understands that proper combustion and accurate reporting go hand in hand and should be viewed holistically so that operators are efficiently managing both concerns.

Meters available in the market and widely used in upstream oil and gas applications include differential pressure meters (e.g., orifice plate and v-cones), thermal mass meters, and ultrasonic meters. Differential pressure meters work by measuring the upstream and downstream pressure from a plate or cone with an orifice that allows gas to pass through. The amount of differential pressure can be increased or decreased for any given flow rate by selecting plates or cones with smaller and larger orifices. The flow of the gas passing through the meter can be inferred by the differential pressure between both points. The ratio of minimum and maximum capacities of meters, known as the turndown ratio, typically should not exceed 4:1 for differential pressure. This causes three primary considerations for differential pressure meters: first, they are inaccurate in low-pressure conditions; second, they are unable to accurately measure variable flow rates given their relatively tight turndown ratio (Zhang & Wang, 2021);[27] and lastly, they are sensitive to liquid and debris clogging the orifice causing an artificial increase in differential pressure and inaccurate high flow volume measurements. The relationship between low-pressure conditions, tight turndowns, and sensitivity to operating conditions is exacerbated by the fact that smaller orifices must be selected for lower pressures, causing even tighter turndown ratios that are more inaccurate with variable rates, and increasing the likelihood of clogging. Orifices can also become blown out by sudden increases in flow volume or debris, which causes a decrease in differential pressure and inaccurate low flow volume measurements. This makes differential pressure meters technically infeasible to measure purge, sweep and auxiliary gas lines that operate at low pressures, tank vent lines that operate at near atmospheric conditions, and high-pressure gas lines that are more variable than the turndown ratio of these meters.

Thermal mass meters operate on the principle of thermal dispersion, which states that the amount of heat absorbed by a fluid is proportional to its mass flow. These meters work by either comparing heat loss between two elements, or by measuring the amount of energy that must be expended to heat gas to a certain setpoint. Similar to differential pressure meters, thermal mass meters cannot accurately detect lower flow rates due to the unmeasurably small differences in temperature between the two elements or energy required to heat gas for low flow volumes. As noted in Kerr-McGee's letter to Colorado Department of Public Health & Environment Air Pollution Control Division (APCD) dated April 12th, 2022[28], the turndown ratio of thermal mass meters is typically 33:1, which means the meter is unreliable until 3% of the meter's maximum flowrate of 1,180 thousand standard cubic feet per day (MCFD) is achieved. Additional information regarding this comment can be found in Annex C of this letter. This also makes thermal mass meters technically infeasible to measure pilot/purge gas lines and tank vent lines as these streams do not meet the minimum flowrates required for thermal mass meters due to their low rates and declining production over time. In addition to issues with low flow rates, thermal mass meters are highly susceptible to entrained mist, liquid, or particles that can affect the

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[27] Zhang, Y and Wang, J. *Review of metering and gas measurements in high-volume shale gas wells*, Journal of Petroleum Exploration and Production Technology, 12:1561-1594, December 2021, https://doi.org/10.1007/s13202-021-01395-9.

[28] APCD-PHS-EX-035.

thermal properties of the gas being measured (API, 2021).[29] For example, the specific heat capacity of propane increases from 1.67 kJ/Kg-K in the gaseous phase to 2.4 kJ/Kg-K in the liquid phase. Thermal mass meters can measure dry gas in steady flow conditions above their minimum capacity, which makes them suitable for select flare scenarios depending on facility design and process. However, they do not have the level of accuracy required to form any basis for the methane fee.

Ultrasonic meters operate on the principle of doppler shift by measuring the time it takes for sound to travel from an ultrasonic signal transmitter to a receiver upstream and downstream of gas flow. Generally, ultrasonic meters do not work well in low flow conditions because of the unmeasurably small doppler shift that occurs at lower velocities. Thus, they are technically infeasible to accurately measure low pressure pilot/purge gas and storage tank streams. They are also sensitive to mist, liquids, or particulates that may block the receiver from receiving the ultrasonic signal, but not as much as differential pressure or thermal mass meters. They are also sensitive to surrounding equipment that may produce vibrations or sounds near the same frequency as the ultrasonic signal. For more information, refer to *API Manual of Petroleum Measurement Standards*, Chapter 14.10.[30]

It is important to note that meters can only be used when facilities have a dedicated high-pressure flare as opposed to a single control device (i.e., a flare that controls tanks, associated natural gas (ANG), and potentially other sources). Ultrasonic meters are also economically infeasible given they can cost $20,000 to $30,000 each to purchase, and additional capital required for installation and labor. API commented on this in our comments on NSPS OOOOb and EG OOOOc Supplemental Proposal, submitted on February 13, 2023, and included in Annex C of this letter. Furthermore, this does not include the cost to install SCADA communications systems that can cost up to $100,000 per facility for unconnected remote locations.

Proposed Parametric Monitoring Does Not Provide a More Accurate Alternative

The proposed alternative of parametric monitoring does not provide a more accurate or cost-effective alternative to metering.

Based on operator experience, field testing programs comparing parametric monitoring and metered flare volumes have shown that parametric monitoring over-estimates flow volumes. Implementing parametric monitoring to estimate flow is complex and requires detailed data on the appropriate flow orifice diameter, installing additional instrumentation to monitor temperature and pressure difference across the orifice, as well as the need to install SCADA communication systems at remote locations and analytical software to estimate flow rate. The requirement to either install meters or parametric monitoring systems is burdensome and unnecessary considering that the main contribution to GHG emissions from flaring is unlit flares, which are addressed separately in the proposed rule.

For all the reasons stated above, **the Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations** that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.

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[29] American Petroleum Institute (API), *Manual of Petroleum Measurement Standards, Chapter 14.10, Natural Gas Fluids Measurement – Measurement of Flow to Flares*, Second Edition, December 2021.
[30] Ibid.

3.8.1.2 Proposed Flare Flow Measurement and Monitoring Requirements are Overly Burdensome

The cost and burden associated with measuring every stream is significant and understated by EPA.

Continuously measuring flow volumes or utilizing parametric monitoring devices for each source that routes gas to a flare will be extremely burdensome while failing to result in more accurate emissions reporting. Many operators have thousands of flares that would be affected, requiring either new meters or parametric monitoring devices. The majority of flares would require at least two gas streams to be monitored - the main vent line or “waste gas” stream and the purge/sweep/auxiliary gas stream. The cost and burden impact of monitoring – at a minimum – must include:

- Minimum of 2 or more specialized meters, or parametric monitoring systems
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the run for the meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expending or adding the remote transmitting unit
- Calibration and maintenance
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

The capital and operational costs to continuously monitor flare volumes using meters or parametric monitoring devices, as proposed, would result in significant costs to reporters that were not adequately addressed in the proposed rule’s burden assessment. EPA did not explain the cost estimates in Table A-3 of “Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," and we note that significant contributions to cost and burden were likely not included in the analysis based upon the magnitude of the estimate. As important, however, is the unjustified acceleration of installation of equipment that is already anticipated over the course of the next few years.

Paradoxically, this increased capital and operational cost can lead to flare volumes becoming less accurate than using the methodology under the current rule, as described below.

The requirement to continuously monitor at least two streams for thousands of flares at remote locations across the upstream oil and gas industry would require significant capital and operational expenditure with little benefit given the legitimate concerns regarding meter accuracy. As noted above, continuous monitoring flare flow volume would require costly specialized meters. As such, the Industry Trades believe EPA has underestimated the capital cost burden for purchase and installation of continuous parameter monitoring systems. The Industry Trades provided the Office of Management and Budget (OMB) this comment in response to Docket ID EPA-HQ-OAR-2023-0234.

3.8.1.3 *Proposed Timeline for Flow Measurement or Monitoring is Unrealistic*

If EPA does not continue to allow process simulation and engineering calculation for flare flow volumes, we are concerned about EPA's proposed requirements to expedite the installation of additional continuous monitoring systems on flares.

The deployment of new continuous metering or parametric monitoring equipment can pose significant challenges. This is particularly true for extensive oil and natural gas production sites and midstream assets, as they often lack SCADA systems or comparable infrastructure. This deficiency limits the connectivity of in-field instrumentation and access to a data historian. Additionally, the absence of necessary infrastructure, such as electricity and data infrastructure including Wi-Fi and even cellular coverage, further diminishes any cost-effective means for installing new instruments.

Existing supply chain delays would only be exacerbated by requiring flow meters on flares as proposed. Operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for flow meters; these timelines are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. These timelines account only for supply chain delays and do not contemplate the additional time needed to install equipment. These supply chain challenges for flow meters and other equipment were documented in a blinded operator survey submitted to EPA on September 20th (and included in Annex E of this letter).

As noted in API's previous comments on NSPS OOOOb and EG OOOOc:[31] "In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk. Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap." Like the supply chain delays, finalization of NSPS OOOOb and the potential need for flow meters under Subpart W would only exacerbate current installation timelines. Instead of requiring all flare stack emissions to install flow measurement by January 1, 2025 (less than 18 months between the proposed rule and the applicability date and likely less than 12 months from final rule) the proposed revisions should allow operators to transition to measurement data as it becomes available through the implementation of NSPS OOOOb or EG OOOOc, which will incorporate practicable implementation schedules for monitoring requirements.

3.8.2 Pilot Flame Monitoring

The Industry Trades generally agree that it is more appropriate to identify discrete periods where flares are unlit for the purposes of estimating emissions that go un-combusted; however, several revisions should be made to the specific requirements:

1. **Double counting of emissions during periods of time when the flare is unlit should be avoided.** Because operators will identify discrete periods of time where the flare is operating with 0% combustion efficiency and report emissions accordingly, this volume of emissions should not be included in destruction/combustion efficiency (more in section 3.8.4 below).

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[31] Comment 5.2. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428

2. Monitoring for the presence of a pilot flame or combustion flame using a device capable of detecting that the pilot or combustion flare is present should **only be required for periods of time where there is flow of regulated material** going to the flare rather than "at all times."
   - (i) It is illogical to track the length of time a flare is both unlit and there is zero flow because it has no impact on the estimated emissions.
   - (ii) Additionally, automatic ignition systems have been deployed many operators and include a flame monitoring device. Since these devices include a flame monitoring device, they would satisfy the obligation, where EPA affirms the requirements for monitoring only apply during periods of flare flow. To reduce emissions or in areas where supplemental gas is needed because the well does not produce gas or enough gas, many operators are installing automatic ignition systems that activate when flow to the flare is detected instead of maintaining a continuous pilot flame. By design, an automatic ignition system will be unlit during periods with no detectable flow to the flare or the valve to the flare is closed. Some state rules, such as in New Mexico and Texas, allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).
3. **Additional monitoring flexibility will improve accuracy of reporting and should be afforded to the pilot monitoring**. The Industry Trades recommend either removing the sentence in 40 CFR 98.233(n)(2), stating "if you continuously monitor, then periods when the flare are unlit must be determined based on those data" or revising it to allow redundant and/or additional parametric monitoring or visual inspection to be used. This is because monitoring device malfunctions are not uncommon for thermocouples (or equivalent devices) resulting in false readings; however, other monitored parameters can confirm that the pilot is, indeed, lit even if the monitoring device errantly indicates the pilot is unlit. For example, operators that have flares with multiple thermocouples to monitor flame temperature report that the readings can be widely variable and have observed that the presence of a flame can be indicated by a single thermocouple within the installed group. There are also cases where a pilot has malfunctioned, but visual inspection using site visits or cameras on location reveal a robustly lit combustion flame. In extreme weather conditions, such as in Alaska, Wyoming, or North Dakota, the thermocouple reading will be affected by the ambient temperature and wind conditions. So, where a monitoring device indicates the absence of a pilot flame or combustion flame, an operator should have the option to confirm that finding through other means and eliminate that period from the log of time in which the flare is unlit if supported by other data.
4. As an alternative to thermocouple monitoring, the Industry Trades recommend that visual inspections can be performed using cameras on location.

The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).

3.8.3 Gas Composition Requirements

Similar to the discussion regarding requirements for flow monitoring in this letter, the Industry Trades **urge EPA to retain the option "to use the appropriate gas composition for each stream of hydrocarbons going to the flare" in the absence of a continuous composition analyzer.** The proposed requirements to either use a continuous composition analyzer or take quarterly samples are both unnecessary (source flow composition is relatively stable at oil and gas facilities) and potentially conflict with the specific requirements and implementation timing of compliance assurance requirements in NSPS OOOOb and EG OOOOc.

EPA should provide an option to use process models for flared gas, which is how most compositions are currently being determined and with reasonable accuracy.

The proposed requirements to measure or sample the gas composition for each flare are economically and technically infeasible, and engineering estimates and representative analysis should be allowed.

EPA's requirement that quarterly gas samples be pulled for each stream that goes to flare has no basis and was not addressed in the proposed rule's TSD. The proposed requirement to install a continuous gas analyzer or take quarterly samples of the inlet gas to every flare is unreasonable and burdensome for several reasons.

1. **The gas composition is relatively stable over time rendering more frequent characterization of low value**. Flare gas composition in oil and gas operations is relatively stable and will not change significantly over time. As discussed above, the primary streams going to flare at typical oil and gas facilities include:
    - Pilot, purge, sweep, and/or auxiliary gas;
    - Low-pressure gas from tank flash, working, and breathing losses;
    - Mid-pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales; and
    - High-pressure separator flaring in areas with stranded gas pipeline take-away loss which is intermittent and decreasing across the country.[32,33]

    EPA also recognized that the gas composition could be stable by proposing an alternate net heating value demonstration in NSPS OOOOb and EG OOOOc[34]. While Industry Trades commented that this demonstration should be simplified due to the relatively stable and generally sufficient heating value of the gas streams, its inclusion in the compliance assurance requirements of NSPS OOOOb and EG OOOOc recognizes that the gas streams could be demonstrated to be stable.

2. **EPA has not justified the costs related to the installation of continuous composition analyzers or quarterly sampling, and go beyond NSPS OOOOb and EGOOOOc compliance assurance requirements**. Installation of a continuous monitor for each stream or quarterly sampling will be

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[32] https://www.api.org/news-policy-and-issues/blog/2022/05/24/reports-us-among-world-leaders-in-reducing-flaring.

[33] https://www.hartenergy.com/exclusives/us-reduces-flaring-and-flaring-intensity-world-bank-says-204724.

[34] Proposed § 60.5417b(d)(1)(viii)(C)(1) to (5).

extremely costly for installation, data gathering and management, calibration and maintenance or sampling and analysis for the thousands of flares impacted. Costs for continuous monitors include:

- Monitor(s) (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the continuous analyzer
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expending or adding the remote transmitting unit
- Calibration and maintenance of the monitor
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

For quarterly sampling, the associated costs include:

- Minimum of 2 sample ports (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting of the flare line for the sample ports
- Cost of gathering the samples each quarter
- Cost of analyzing the samples every quarter
- Data management system
- Data review and analytics
- Data entry for calculations

Flare systems in upstream operations are not designed for sampling, meaning that physical modifications to install sampling ports would be required to enable samples to be taken, which is costly and not always technically feasible. Also, installing sampling ports, meters/instrumentation, or continuous gas analyzers would require production to be shut down, which would be logistically challenging and generally result in flaring to accommodate causing more emissions.

As noted in API's comments on NSPS OOOOb:[35] "Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000." The estimated cost per gas sample was "$1,500 to $2,000 including shipping and analysis." Therefore, the annual cost for quarterly sampling could easily exceed $10 million for an operator considering 4 samples per year per stream, at least 2 streams per site, and a thousand or more sites to sample annually.

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[35] Comment 5.6.4. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.

Finally, a continuous compositional monitor or quarterly sampling goes beyond the continuous net heating value (NHV) monitoring or NHV demonstration required under proposed NSPS OOOOb and EG OOOOc. As stated at the beginning of this section, Subpart W must not impose monitoring requirements beyond other applicable regulations. While a continuous compositional monitor could be used for NHV monitoring, compositional analyzers (e.g., gas chromatographs) are more expensive than NHV monitoring devices (e.g., calorimeters). Given the relatively stable composition of gas streams and cost for compositional monitoring, Subpart W should simply reference NSPS OOOOb and EG OOOOc monitoring requirement as they relate to methane destruction efficiency (see comments bellow) and not impose additional composition monitoring requirements.

3.8.3.1 Supply Chain Constraints

As noted above for flow meters, operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for monitoring equipment for flares; these delays are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. Requiring compositional monitoring under Subpart W would further exacerbate the existing supply chain constraints with minimal benefit to reported GHG emissions.

3.8.3.2 Technical Feasibility Issues

Additionally, it is technically infeasible to pull gas samples from low pressure flares. A positive pressure is required to pull gas samples from flare lines. Low pressure flare vent lines operate at near atmospheric conditions, which would either take hours to collect a large enough sample (i.e., fill a bag with enough gas) to send to laboratory for analysis or require a gas chromatograph equipped with a pump to be brought on location. Requiring a gas chromatograph to pull quarterly gas samples is economically infeasible.. Process simulation would be a more accurate representation of tank gas. It would be equally difficult to pull samples for mid- and high-pressure flaring given the intermittent nature of these events. A more accurate representation of high-pressure gas composition, as well as pilot/purge gas, would be sales gas composition which is ultimately what is being combusted at the flare. Finally, as stated above, EPA does not address why this frequency in sampling is being proposed in either the Technical Support Document or the preamble.

3.8.4 Variable 'Combustion Efficiency' Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

3.8.4.1 NESHAP CC Requirements Are Not Applicable to Subpart W Flares

The reference to and requirements from refinery NESHAP CC are not applicable for Tier 1 reporting under Subpart W.

EPA should remove any tier requirement related to NESHAP CC for refineries because the characteristics of the flare designs, operating conditions, and composition variability are not representative of, and in fact quite dissimilar from, petroleum and natural gas systems flares.

The Industry Trades believe the reference to NESHAP CC which applies to petroleum refineries is inappropriate. There are numerous ways in which refinery and chemical manufacturing flares and flare gas differ from that of upstream and midstream.

- Flare gas composition and flows span large ranges: Refinery flares receive flare gas of highly variable composition and of varying levels of heat content. Refinery flares can be dedicated to one or more related process units but are quite often very large and in service to many different process units, or even operate as a single interconnected system. Resultantly, the range of flows and composition to the flare is highly variable over a matter of hours. The heating value of the streams is typically much higher in upstream and midstream with the high-pressure gas being primarily natural gas and the gas from secondary separators, heater treaters and vapor recovery towers having a higher heating value greater than 2000 btu/scf. Except for the minority of wells that produce inert gases, where the composition of that production is known, flare gas streams are always highly combustible.
- Because refinery and petrochemical manufacturing flares combust gases with greater propensity to produce smoke (e.g., concentrations of olefins, diolefins, and aromatics) and thus are generally designed with an emphasis on smoke control, often including one or more steam addition systems, there is a documented risk of “over-steaming” for these flares. Less frequently, refinery and chemical manufacturing flares are air assisted, and even more rarely, unassisted. The reverse trend is true for upstream and midstream flares, where steam assist is the exception to the norm. Utilities to support steam assist are generally not available, upstream flares are less likely to need commensurate smoke suppression systems, and upstream and midstream flares are much smaller and dedicated units.
- While upstream operations are also actively seeking to reduce flaring, Refinery and chemical manufacturing flares also often have an obligation to flare gas minimization. Accordingly, any routine flaring that exceeds the flare gas recovery capacity of the facility results in flaring at extremely high turn-down conditions for the flare. High turn-down (<0.1% of flare capacity) at a steam-assisted flares presented the perfect storm for degraded combustion efficiency, which drove the enforcement initiative, subsequent ICR testing, and ultimately rulemaking to address this specific conditions. This condition does not exist in the up- and midstream segments.

3.8.4.2 EPA Should Allow Direct Measurement and Performance Testing for Flare Methane Destruction Efficiency

Direct measurement and performance testing by manufacturers or operators should be accepted as an optional demonstration of even greater destruction efficiency beyond 98%.

The Industry Trades request that EPA allow directly measured data, as well as NSPS performance testing by manufacturers or operators, as a more accurate approach to quantify an individual flare’s methane destruction efficiency. Whether or not a flare is monitored pursuant to NESHAP CC or NSPS OOOOb has no actual bearing on the flare combustion efficiency values. Even if a flare meets the monitoring requirements of either rule, it does not necessarily follow that the actual flare combustion efficiency is at the respective values. For example, flow volume values may indicate flow exceeding minimum or maximum flows which is an indicator of potential suboptimal combustion efficiency. Additionally, if all monitored flare values are within performance standards, the flare combustion efficiency could be higher than the specified combustion efficiency for the specified tier. As is standard practice with GHG estimation methodologies, the timing and values of detections, measurements, and parametric data—not whether monitoring requirements are met--determine emission rates, such as flare combustion efficiency. Thus, the Industry Trades recommend that EPA supplement the tiered monitoring approach to flare combustion efficiency reporting to include directly measured data or NSPS performance testing by manufacturers or operators.

Some operators are deploying emergent technologies to directly measure combustion efficiency (or the closely related destruction efficiency) for flares, such as Providence Photonics Mantis and Mantis light (additional information regarding this technology is available in Annex D). Many operators, either through state or permit requirements, or voluntarily, conduct more traditional stack testing to assure high combustion efficiency of enclosed combustors, which also meet the definition of "flare" in Subpart W. Both of those testing methodologies provide the most accurate estimate of any particular flare and should be allowed as an option.

EPA should also allow for the use of the recently finalized "Other Test Method (OTM 52): *Method for Determination of Combustion Efficiency from Enclosed Combustion Devices Located at Oil and Gas Facilities*,"[36] using Portable Analyzers to determine destruction or combustion efficiency.

These approaches would further support technology development and allow for flexibility in using advanced and evolving technologies. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program (REMEDY | arpa-e.energy.gov) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in flares. If technology development from this 3-year, $35 million research program is successful, the ability to use a higher flaring efficiency value in methane emissions reporting could help to drive greater adoption of new technologies in operations.

3.8.4.3 Requirements for Proposed Tier 2 Support 98% Methane Destruction Efficiency

The compliance assurance provisions in NSPS OOOOb and EG OOOOc, as proposed under Tier 2, are sufficient to ensure 98% methane destruction efficiency.

The underlying goals of the flare compliance assurance provisions in part 63 subpart CC flare requirements was to supplement the provisions in 60.18 to specifically protect against over steaming, especially in concert with lower heat content flare gas by transitioning the compliance point from heat content of flare gas to heat content reaching the combustion zone, which would account for inert gases introduced to the flare gas within the variable gas composition in manufacturing settings, and account for the impact of steam on the combustion zone. In the absence of those conditions, 60.18 provisions continue to provide a reasonable assurance of high combustion efficiency.

Further, a recent study on flare destruction and removal efficiency (DRE) conducted in the Permian Basin by members of the Industry Trades indicates that over 85% of flares have a destruction efficiency above 98% (refer to comment below in Section 3.8.4.4). Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. These findings support a 98% combustion efficiency default for Tier 2, especially considering the enhanced monitoring requirements aligned with NSPS OOOOb rule requirements.

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[36] https://www.epa.gov/system/files/documents/2023-09/otm-52_method-for-determination-of-combustion-efficiency-from-enclosed-combustors_clean_8_31_2023-004.pdf.

3.8.4.4 Tier 3 Methane Destruction Efficiency Should be Revised to a Minimum of 95%

Destruction Efficiency of 95% Supported by Plant *et al* Study

The default proposed 'combustion efficiency' in Tier 3 reporting is based upon errant analysis in the Plant *et al* study and a more appropriate interpretation of those data would result in an overall methane destruction efficiency of >95% across upstream and gathering and boosting flares.

The Plant *et al* published study results state that 'the majority of flares function close to expected performance, with DRE values near 98%.'[37] The study concluded that approximately **95% methane destruction efficiency was the average across the basins in the study without accounting for unlit flares**. Since Subpart W already requires the monitoring of and segregation of periods where flares are unlit, it is not appropriate to *also* include that condition in an average destruction efficiency assumption. The average observed DRE across the three regions of study is 95.2% and the average total effective DRE after accounting for unlit flares is 91.1%.[38] The lower 'combustion efficiency' proposed by EPA is not aligned with the methane destruction efficiency findings from the Plant *et al* study, and represents the inclusion of unlit flares, **meaning that the unlit flare contribution would effectively be double counted since unlit flares are reported separately.** Therefore, 95% methane destruction efficiency would be more appropriate for Tier 3 as supported by the study referenced by EPA (rather than 92%). This 95% destruction efficiency would be aligned with NSPS OOOO and OOOOa control requirements; requiring a Tier 3 efficiency of 92% would not be aligned with other applicable requirements.

Furthermore, in the Plant *et al* study, investigators did not have access to operational data, including flow information, for any of the observed flares. Resultantly, extrapolation of the observations to a regional emission factor inherently assumes that the set of flares observed well represented the population of flares in terms of size, design, and most importantly, flow rates. In the case of refinery and petrochemical plant flare combustion efficiency studies, it was found that flares most at risk for reduced combustion efficiency were those operating at high turndown (low flow) conditions. Low flows also result in reduced exit velocity, where higher exit velocities are more protective against cross-winds. Therefore, it is quite plausible that the majority of the flares encountered in the Plant *et al* study that were operating at reduced combustion efficiencies were flares at low flows. However, the authors applied the destruction efficiencies by *count* of flares to regional flare gas estimates from the Visible Infrared Imaging Radiometer Suite (VIIRS), which inherently incorporates an assumption that flare gas was evenly distributed among the observed flares and that flare turndown was not correlated to combustion efficiency degradation.

Validity of the Plant *et al* Study Data is Questionable

The validity of the Plant *et al* study data as the sole underlying basis for quantifying flare methane destruction efficiency is questionable.

There are several limitations of the Plant *et al* study, most of which are raised by the authors themselves within the study and quoted below. These limitations raise questions about the study validity as a basis for establishing a 3-tier combustion efficiency framework and a presumptive Tier 3 value of 92%. These include:

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[37] https://graham.umich.edu/media/files/F3UEL-Fugitive-Emissions-from-Flaring.pdf.

[38] Ibid.

- The study design did not disclose how the flight-path test method (i.e., ‘shifting racetrack’ pattern) was validated, for example, using a well-characterized source of CO2 and CH4 or a test flare having known input flow rates, combustion characteristics, and dispersion behavior. Without documentation of method validation using a model source, peer reviewers were, and end-users are, unable to determine how the field sampling techniques were calibrated, and the appropriateness of the error correction / statistical treatment applied to the collected information to address test method-induced artifacts.

- There were no data presented on the vertical or horizontal dispersion effects or on the ability of the sampling technique to discern the presence of imperfect distribution of CH4, CO2 or other components within the sampled plumes. In fact, in the Supplementary Materials[39] the authors noted that (emphasis added), “In real-time, the concentration reading of CO2 was monitored to look for an intercept (i.e., peak) of the ***relatively narrow flare combustion plume as the aircraft transected downwind. If an intercept was not identified on the first downwind pass, the flight team adjusted altitude, using the visual flare as a guide***.” This statement confirms that each sample event would likely have employed a unique flight path, introducing an inconsistency across individual runs in the dataset.

- The sampling scenario was challenging. As noted in the Supplementary Materials[40], “In real-time, the concentration reading of CO2 was monitored to look for an intercept (i.e., peak) of the relatively narrow flare combustion plume as the aircraft transected downwind.” No information was available to readers to determine the parameters of each flight path. Using publicly available information for the aircraft and assuming a circular flight path, the estimated dwell time of the aircraft in the plume during each pass was likely extremely short. The Scientific Aviation Mooney aircraft have a cruise speed of 170 knots (or higher)[41] with stall speeds of 50-60 knots[42,43] according to various sources. At a speed of 130 knots[44] in a 6500ft diameter circular flight pattern, and assuming a 10° sample window (570ft), the dwell time in the sample window is less than 2.5 seconds. Even with a wide 22.5° sample window (1275 ft), the dwell time in the sample window is just 5.5 seconds. Higher air speeds would shorten the dwell times.

- The study acknowledged that the log-normal curve-fitting technique used likely leads to overweighting the importance of the outlying data, thus magnifying the influence of tails even though the authors noted that the median observed DRE values were close to 98%. Also, the authors could not explain the outlying, tail-defining observations collected (emphasis added), “Investigations into possible drivers of reduced DRE… did not yield compelling explanatory relationships, suggesting that the combination of our airborne sampling and these supplemental datasets ***cannot explain most of the observed flare CH4 DRE variability***.” Also, the authors did not solicit input from operators about operating conditions that could explain the observed

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data. Given the influence of the low DRE datapoints, further scrutiny as to their validity and possible exclusion from the dataset should have been made.

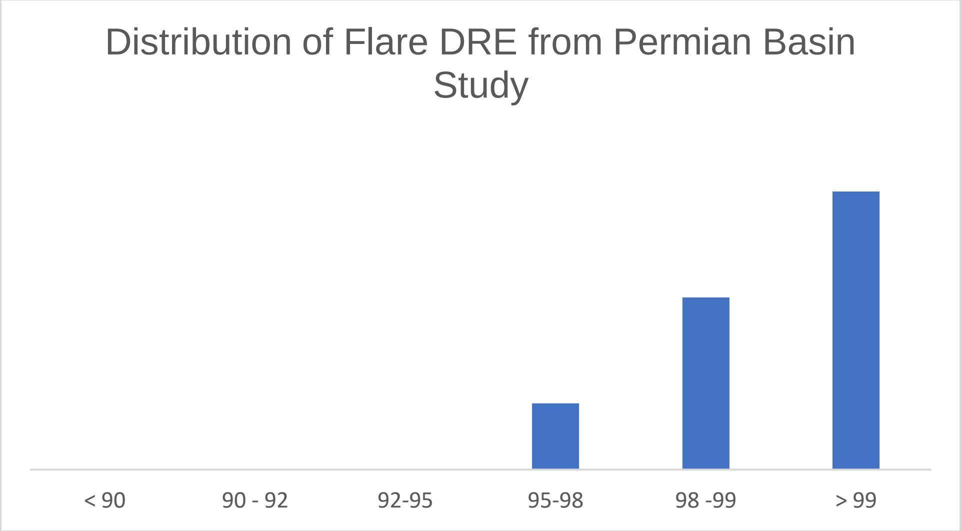
- The Plant *et al* study did not provide information on the rate, duration and variability of the gas being flared at each location, nor what activity precipitated the flaring, such as: flowback from a single well, emergency operations during drilling or a workover, a lightning strike that shut down control systems, a gas compressor failure, malfunction of a tank or separator liquid level or other controller, on a well pad co-located with the flare or at a central gathering and boosting facility, upset at a gas treating unit co-located with the flare, shut-in of a downstream gas plant forcing gas to be flared from multiple upstream sources etc. Absent this information, it is impossible to determine what separated high-performing flares, from those that exhibited low DREs and whether the low-performing flares represent the effect of transient anomalies that cannot be assumed to be present basin-wide for extended periods of time.

- The use of "bootstrapping sampling" to extend to basin-scale the data from the limited sample set collected via aircraft sampling magnifies the weaknesses discussed above and should not be the basis for a regulatory change. The Plant *et al* study authors combined contributions of both observed" inefficient **performance (*i.e., CH4 DRE*) and the prevalence of unlit flares into a total effective DRE."** This was done by randomly resampling (with replacement) the observed DRE distributions and applying those efficiencies to the population of flares seen in VIIRS within each basin. Essentially, this manipulation of the data multiplied the small observed dataset many times over. Then the authors ***inferred the uncertainty*** (emphasis added) of basin-average estimates to derive 95% confidence intervals. This approach does not support the use of the word "found" in the following statement made in the preamble: "Plant *et al*. … ***found*** average combustion efficiencies ranging from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin."

Member-Provided Data Supports a Destruction Efficiency Well Over 95%

Additional flare destruction efficiency data provided by Industry Trade members indicate that all but two flares out of 132 tested achieve a destruction efficiency of over 95%, with the majority (nearly 90%) achieving a destruction efficiency greater than 98%.

In September 2023, API members conducted a flare study on 39 flares throughout the Permian Basin using Providence Photonics Mantis. Due to the limited timeframe in which to prepare comments, this study was limited to 39 flares; however, the study found that 85% of flares achieved a destruction efficiency greater than 98%. All flares achieved a destruction efficiency greater than 95%, as shown in the Figure below.



Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, and one measurement in the Permian, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. All but two flares out of 92 tested had a destruction efficiency above 95% (i.e., 94.85% and 90.52 %, respectively). The table below summarizes the distribution of methane destruction efficiencies calculated from member-provided flare testing in both the Permian and Bakken basins:

Basin	Number of Flares Tested		Mean Flare Destruction Efficiency, %	Median Flare Destruction Efficiency, %
Permian	40		98.82	99.05
Bakken	92		99.27	99.69
Combined	132		99.14	99.50

As shown, the median flare destruction efficiency for the combined dataset of 132 flares tested from the Permian and Bakken was 99.5%. **These studies further reinforce that the Tier 3 destruction efficiency should be a minimum of 95%. Arguably, the Tier 3 destruction efficiency should be considerably higher than 95% based on the test data from members, as the data supports a destruction efficiency closer to 98%.** Please see Annex D for a summary of the test results.

3.8.5 Completion Combustion Devices Should not be Subject to Proposed 98.233(n)

Requirements for completion combustion devices used during completions with hydraulic fracturing should not be required to have the same monitoring provisions as flares under 98.233(n).

For completions with hydraulic fracturing in 98.233(g), EPA has proposed operators to follow the requirements listed in 98.233(n), which include extensive monitoring requirements. Under existing air quality regulations and proposed NSPS OOOOb, combustion of emissions that cannot be routed to sales, such as for wildcat or delineation wells, are combusted using a completion combustion device. This equipment has a separate definition and compliance assurance requirements from typical control devices based under NSPS due to the temporary use of these devices during a completion event. The proposed requirements under 98.233(n) are inappropriate and EPA should, at a minimum, have appropriate provisions that allow engineering estimates for completion combustion events. Completion combustion devices must be equipped with a reliable continuous pilot flame under NSPS.

3.8.6 Disaggregation of Flare Emissions

When data is not available to allow disaggregated reporting by individual sources controlled by a flare, EPA should allow aggregated emissions reporting by flare.

The Industry Trades understand that EPA wishes to allocate all individual sources controlled by a flare back to the contributing source. The Industry Trades support maintaining the ability to report emissions aggregated by flare when more accurate data is not available. As addressed in the "Flares" section of this document, metering individual sources may not result in more accurate data. Allowing the flexibility to continue reporting flare sources aggregated will give companies the ability to report the most accurate data available given a particular facility's operational design. However, it is important to note that EPA has not stated a clear benefit from requiring the disaggregation of sources, and therefore a true cost/benefit analysis cannot be determined.

3.9 Centrifugal and Reciprocating Compressor Venting

3.9.1 Measurements in Not-Operating-Depressurized Mode

The Industry Trades support EPA's efforts to increase the accuracy of reported information for venting from centrifugal and reciprocating compressors by allowing direct measurement, but measurement should not be required in Subpart W if not required in other regulatory programs. Additionally, Subpart W should not force operators to measure emissions in a not-operating depressurized mode.
EPA's proposed expansion from an emission factor to measurement approach for onshore production and gathering and boosting will further improve the quality of reported emissions across the segments. The Industry Trades support the expanded assortment of measurement methodologies and appreciate EPA's use of data from other programs (e.g., proposed NSPS OOOOb and EG OOOOc) for emissions calculations under subpart W, however there are numerous issues with the proposal. Although the compressor measurement provisions have been expanded from the gas processing reporting source category to include onshore production and gathering and boosting, there are unique differences that should be accounted for within the proposed requirements. The Industry Trades have provided suggested edits to account for these differences.

EPA is proposing to require that onshore production and gathering and boosting operators shall measure at least one-third of their reciprocating and centrifugal compressors subject to NSPS OOOOb in not-operating-depressurized mode each year. The Industry Trades do not support this requirement for several technical, safety and practical reasons. The Industry Trades recommend that EPA align with proposed NSPS OOOOb and EG OOOOc and limit the measurements to the rod packing for reciprocating compressors and dry seal vents for centrifugal compressors. Testing the compressors in a not-operating depressurized mode is unnecessary and very difficult to implement for the following reasons:

- Forcing a unit into a not-operating depressurized mode will result in unnecessary venting of methane emissions to the atmosphere and could pose an unnecessary safety risk to the testing personnel or others at the site. Operations in upstream production and gathering and boosting segments are characterized by stable operation with full utilization of installed compression capacity. In order to measure emissions in not-operating depressurized mode, a forced blowdown event leading to significant methane emissions would be required for these compressors.

- As a practical matter, it would be very difficult if not virtually impossible for an operator to know at which point during the year to force units into a not-operating-depressurized mode in order to reach a prescriptive annual target. Additionally, the number of units change on a frequent basis due to acquisitions/divestitures, such that the number that would constitute "one-third" changes from month to month. Compressors are also added and removed throughout the year to address operation needs from the wells and gathering system based on production rates.

- In the dynamic operations of upstream and midstream oil and gas, shutting down a compressor for the sole purpose of measuring the venting could result in shut-in and blowdown of other process equipment resulting in additional methane emissions, as well as costly prolonged downtime of a facility. Taking a compressor off-line in production and gathering and boosting segments would result in shutting in a well(s), which can be problematic to restart and regain stable operation. As anecdotal evidence, our members have noted these tests take upwards of three weeks at their 10 gas plants with 140+ compressors. Extending this requirement to upstream facilities that are geographically spread across hundreds of miles would be extensive due to the thousands of compressors in use. The gas plant measurements are streamlined due to the units being co-located and the designed redundancy in place.

- Additionally, due to the integrated nature of the upstream/midstream environment, shutting down compression would not only have an effect on that company, but would additionally impact other companies that are connected to the system (i.e., shutting a compressor down would cause high pressure issues for the upstream operator and low-pressure issues for the downstream operator potentially resulting in additional flare and/or vented emissions for additional companies.

- Methane emissions from compressors in not-operating depressurized mode represent the emissions across the isolation valve, with potentially high flow rates due to the extreme line pressure on the upstream, pressurized side of the valve. Many operators, especially in production and gathering and boosting segments, do not normally operate compressors in this mode due to the potentially large methane leakage and associated safety risks. Additionally, good operating practice is to leave the blowdown/depressurization valve closed when units are offline.

- Finally, many compressors serve a critical function in the electricity generation supply chain and operate with limited or no excess capacity; forcing operators to shut down units to take measurements in a not-operating depressurized mode could strain the electrical generation supply chain. In 2022, the Texas Railroad Commission (TRRC) adopted weatherization rules for natural gas facilities to protect gas flow to power generators and ensure that residents have electricity during weather emergencies. The new rule requires critical gas facilities to weatherize, to ensure sustained operation during a weather emergency. The testing requirements as described would add an additional layer of complexity with little to no emissions reporting accuracy improvements.

3.9.2 Alignment with NSPS Protocols – Measurement of Compressor Sources

In the proposal for NSPS OOOOb, rod packing, and seal vents are the only compressor sources that require monitoring. All other compressor leaks would be captured during the fugitive emissions inspections. The Industry Trades recommend that EPA align with the monitoring and fugitive emissions requirements of NSPS and consider leaks from other sources (e.g., blowdown valve leakage) fugitive leaks. This modification would eliminate the need for specific compressor mode testing and align with other EPA regulations for other sources.

3.9.3 Emission Factor Methodology- Utilize Measurement Data Reported Under Subpart W for Onshore Production and Gathering and Boosting

EPA should utilize the vast dataset of historically reported compressor measurements in different operating modes to derive population emission factors to ease the burden of compressor measurements and reclassify leakage from isolation and blowdown valves (open-ended lines) as equipment leaks.

While we believe all leaks besides rod packing and seal vents should be captured under the fugitive emissions reporting, EPA could consider an alternative to the measurement protocol. This alternative could utilize the vast dataset of compressor measurements in different operating modes historically reported under Subpart W to derive emission factors to reduce the burden of compressor measurement requirements. Because of the large sample size of actual measurement data, methane emissions can be reasonably estimated using emission factors derived from the data reported Subpart W.

Additionally, EPA should consider the use of the historically reported Subpart W compressor leakage dataset to derive population emission factors rather than rely on the much smaller dataset from the Zimmerle *et al* study.

3.9.4 Alignment with NSPS measurement provisions should extend beyond onshore production and gathering and boosting industry segments.

Industry Trades support referring to the data made available through the provisions located at §60.5380b(a)(5) for centrifugal compressors and §60.5385b(b) and (c) for reciprocating compressors at onshore production and onshore natural gas gathering facilities, but do not support incorporating measurement requirements in Subpart W. The Industry Trades recommend that EPA should also do the same for any compressor subject the NSPS OOOOb or EG OOOOc, including those located at onshore gas processing, natural gas transmission and underground storage. Without this alignment for all compressors subject to the NSPS, many operators will be required to calibrate measurements according to two separate standards, which we do not believe was EPA's intent.

3.10 Equipment Leaks

3.10.1 Method 2- Site-Specific Leaker Emission Factors

EPA should allow more flexibility in the requirements for developing site-specific emission factors for equipment leaks.

The Industry Trades support EPA's proposal to allow for directly measured data to develop site-specific emission factors in lieu of the default leaker or population emission factors for equipment leaks. However, the Industry Trades recommend allowing more flexibility in allowing representative direct measurements rather than "site specific." For upstream operations, there can be many components that are representative even if they are not located at the same facility; and the same can be said for the gathering and boosting reporting segment. The Industry Trades recommend that EPA allow representative leak measurements where "representative" could mean components in gas or oil service, component types, and other considerations – but not otherwise limited to a single well pad or boosting and gathering ID.

The number of leak measurements required to develop site specific emissions factors, proposed as a minimum of 50 per component type, is arbitrary; accumulating 50 leak measurements will be difficult for less frequently used component types or operators with fewer sites. The Industry Trades recommend that EPA allow operators flexibility to determine an appropriate sample size using an appropriate statistical approach based on the complexity of the sites (based on variability of the streams at the sites) and available data and modify as more measurements are obtained. The requirement for a sample of 50 leak measurements per component type will penalize small operators with few sites, as the minimum requirement of 50 may not be possible. Further, as operators convert pneumatic systems to air or electric controllers, fewer sites will have natural gas-operated pneumatics. The Industry Trades also recommend allowing multiple years upon which operators can collect measured leak data and refine those factors as more data is available; this will ultimately be more accurate and representative of site conditions than default emission factors that were derived from larger data sets.

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3.10.2 Method 1- Default Leaker Emission Factors

The derivation of the proposed OGI leaker emission factors is unclear and values appear high relative to the underlying studies and would overstate emissions from the more prevalent non-compressor related components.

The Industry Trades support the use of data from the Pacsi *et al* study to develop the leaker emission factors. However, we are concerned about the significantly higher emission factors that EPA has derived from the Pacsi *et al* and Zimmerle *et al* studies, especially for OGI leak detection, as compared to the existing Subpart W and Pacsi *et al* leaker emission factors. When comparing the published study results from Pacsi and Zimmerle to the EPA proposed emission factors (see comparison table below), it is unclear how the proposed emission factors were derived and while a generalized description is provided in the TSD, the supporting calculations are necessary to fully understand the approach EPA has taken.

Component	**EPA Proposed Emission Factors (scf/hr/component)**			**Pacsi et al (scf/hr/component)**	**Zimmerle et al, (scf/hr/component)[a]**	
	OGI	**Method 21 @ 10,000 ppm**	**Method 21 @ 500 ppm**		Non-compressor components	Compressor components
Leaker EFs, Gas Service – Onshore Production & Gathering and Boosting						
Valves	16	9.6	5.5	6.0	7.1	36.9
Flanges	11	6.9	4.0	13.7	6.2	8.8
Connectors	7.9	4.9	2.8	2.8	4.7	11.9
OELs	10	6.3	3.6	8.5	3.94	
PRVs	13	7.8	4.5	1.1	10.0	18.5
Pump Seals	23	14	8.3	-	29.9	
Other	15	9.1	5.3	4.2	21.7	
Leaker EFs, Oil Service – Onshore Production & Gathering and Boosting						
Valves	9.2	5.6	3.3	4.9	7.1	36.9
Flanges	4.4	2.7	1.6	-	6.2	8.8
Connectors	9.1	5.6	3.2	1.1	4.7	11.9
OELs	2.6	1.6	0.93	-	3.94	
Pump Seals	6.0	3.7	2.2	0.23	29.9	
Other	2.9	2.2	1.0	12.7	21.7	

[a] Zimmerle *et al* study published results did not distinguish between gas and oil service.

As shown in the table above, the Zimmerle *et al* study data show and the study report indicates that emissions from compressor-related components have higher leak rates due to vibration. Since EPA did not distinguish between components associated with or not associated with compressors, the average emission factors proposed that appear to include compressor-related components would overstate emissions from the more prevalent non-compressor related components. The Industry Trades request that EPA critically review the derived emission factors and include compressor-related components in the breakdown of leaker emission factors, with commensurately lower emission factors for non-compressor-related components, to avoid significant overstatement of methane emissions from the higher population of non-compressor related components.

Applying gathering and boosting derived emission factors to onshore production with compressor-related component emissions included in the Subpart W emission factors would significantly overstate methane emission because far fewer compressors are operational in production compared to gathering and boosting operations.

The Industry Trades support efforts to properly characterize a leak by the period in which that leak is detected. This will further align subpart W with the proposed methane rule, which mandates that any leaks must be repaired as soon as practicable. To that extent, we recommend EPA amend the definition of $T_{p,z}$ in Equation W-30 to better reflect the implementation of monitoring and repair programs by acknowledging that the duration of the leak may be subject to the action of repair and verification, and not solely by a traditional survey and/or the start or end of the reporting year, similar to what the Industry Trades propose for other leak durations, thief hatch openings, etc.

We also recommend that EPA revise the approach to include other activities in addition to leak detection surveys that may offer an indication of a repaired leak. While the current proposed language refers only to a “survey”, an operator will have other clear indicators that a leak has been addressed including the repair date or other detection approach. EPA should include any other such activity on which an operator seeks to assign a repair date other than a survey as a reporting element.

3.10.3 Enhancement Factor

EPA’s ‘Enhancement Factor” or “k factor” derivation and rationale are unclear; testing of the proposed approach using the underlying study data to corroborate results should be confirmed.

EPA states in the TSD that the Pacsi *et al* study OGI captured approximately 80% of overall emissions, Method 21 (500 ppm leak detection threshold) captured 79% of emissions, and Method 21 (10,000 ppm limit) captured 65% of emissions, respectively. However, the Pacsi *et al* study is clear that even though using Method 21 identified more leaks (293 vs. 113 with OGI), the majority (67%) of additional leaks found were very small (1 scf/hr. or less). Further, both FID and OGI methods, while finding different leaking components, found a very similar total volume of emissions from leaking components at the site.

The Industry Trades disagree with EPA’s proposed “Enhancement Factor” or “k” factor. It seems that EPA has proposed the ”k” factor to account for both method’s quantification differences as well as other variables, such as the percentage of emissions found by survey methods (e.g., due to accessibility of components, etc.). Applying such logic to specific emission factors for specific equipment is not appropriate as the intent seems to include both updates for a specific leak factor for an individual component as well as capturing emissions from other components that may not be otherwise detected (i.e., the remaining 20% or 21% of emissions not directly identified by OGI or M21 respectively in the Pacsi *et al* study). Grossing up individual component emission factors is not a logical approach to account for leaks not directly identified. While the Industry Trades disagree in principle with EPA’s approach, if such an approach were to be applied, it would only be appropriate on an aggregate basis. That is, if EPA were to apply such logic, doing so as part of the National Inventory process would be more appropriate than grossing up emissions from induvial components or individual operators.

Additionally, and importantly, the Industry Trades have been unable to replicate the calculations EPA used to derive the “k” factors and request transparency regarding the approach and use of data relied upon by EPA prior to finalizing any rulemaking. The Industry Trades also request confirmation if EPA tested their “k” factors by applying to the M21 data in order to recalculate the emissions at site level using study data and confirm if it matches with the measured emissions.

3.10.4 Leak Duration

The leak duration should be revised to reflect a more reasonable and representative assumption that the leak duration is half the time since the last survey.

The leak duration associated with the Method 1 leaker emission factor approach should be half the time since the last survey. Assuming that the leak duration was the entire period since the last survey is an overstatement of the leak duration, as it implies the leak occurred on the date of the last survey which is unreasonable. Since the actual time the leak started is unknown, it is more reasonably accurate to assume that, on average, that the leak would have started in the mid-point of the survey cycle. This assumption accounts for that some leaks will occur before the mid-point and some will occur after the mid-point, but that on average, it is a reasonable assumption and much more representative than the conservative assumption that the leak started at the time of the last survey.

3.10.5 Method 3 – Default Population Emission Factors

The proposed population emission factor approach should be revised to improve accuracy of emission factors and component counts, while allowing more flexibility for reporters.

The Industry Trades are concerned that the Rutherford *et al* study (2021) used for the production and Gathering and Boosting emission factor development included infrequent large emitters in the derivation of the emission factors, including emissions from sources covered elsewhere and not considered fugitive components. Additionally, Rutherford *et al* didn't conduct any actual measurements of equipment leaks. The study results are a synthesis of past studies and includes storage tank emissions as fugitives. Given that EPA is now proposing to report large events as “other large releases,” the Industry Trades believe using this study will result in double-counting. The Industry Trades support the use of the Pacsi *et al* and Zimmerle *et al* studies, despite EPA’s concerns noted in the preamble regarding the smaller sample size. The Industry Trades believe the Pacsi and Zimmerle studies to be more appropriate for upstream and midstream operations.

The Industry Trades do not support the elimination of component count method 2 and request that EPA allow the use of actual component counts if it is subject to a state regulatory program that requires component counts.

3.10.6 Leak Detection at Onshore Gas Processing

Industry Trades generally support the updated definition of onshore natural gas processing that align with New Source Performance Standards as proposed in 98.230(a)(3). This update provides the regulated community with much needed alignment between regulatory programs and removed the confusion for reporting emissions under subpart W based on the previous definition included in the GHGRP.

However, the Industry Trades request that **CO_2 plants be included within the Onshore Gas Processing segment definition**, and not under the Gathering and Boosting definition.

Additionally, there are additional clarifications that are needed from EPA to the proposed equipment leak provisions as it pertains to onshore gas processing to better align with existing and proposed NSPS provisions.

The proposed use of NSPS OOOOb and EG OOOOc surveys for calculating emissions should be clarified and expanded.

EPA has proposed the following text at 98.233(q)(1)(vi)(F) to require the use of NSPS OOOOb and OOOOc survey data in calculating emissions from equipment leaks at onshore natural gas processing plants:

> *For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), including components which are considered inaccessible emission sources as defined in part 60 of this chapter.*

Industry Trades recommend the following updates to this requirement:

- **Inclusion of alternate leak standards**: References to § 60.5400b should also include a reference to the alternate equipment leak standards in § 60.5401b to clarify that both OGI surveys conducted according to Annex K and Method 21 surveys with a 500 ppmv leak definition should be used in emission calculations.
- **References to the equipment leak standards under the earlier NSPS KKK, OOOO, and OOOOa** should be included so that survey data can also be used in emission calculations. While the earlier equipment leaks standards were for VOC only as opposed to the VOC and methane under NSPS OOOOb and EG OOOOc, some components in VOC service (>= 10 wt% VOC) may also be required to be surveyed under Subpart W (>=10wt% CH4 + CO2), and the monitoring technique in the earlier NSPS are already included in the approved list in 98.234(a). This update would allow operators to avoid potentially duplicative surveys.
- **The inaccessible component exemption should be retained under Subpart W.**[45] For onshore gas processing, the term "Inaccessible" has a long-standing meaning under NSPS, which historically is limited to connectors that are monitored using Method 21 with specific criteria that extends well beyond the 2-meter clause noted in 98.234(a). This exemption is directly linked to the safety of our personnel or the technical use of monitoring equipment. Specifically, connectors that are *"buried"* or that are "*not able to be accessed at any time in a safe manner to perform monitoring (Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or*

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[45] EPA has proposed the following language per 98.234(a): Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year. For components located in the onshore production, natural gas gathering and boosting, transmission compression and underground storage (i.e. well sites, central production facilities, or compressor stations), the language proposed aligns with those that are identified at difficult-to-monitor when using M21 per the provisions in NSPS OOOOa and proposed NSPS OOOOb/c. The difficult-to-monitor components require annual monitoring under NSPS, which are consistent with the proposed language in 98.234(a). EPA could be consistent and use the term difficult-to-monitor if that was EPA's intent.

> *uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment)"* should not require additional leak detection provisions under subpart W.

3.10.7 Expand List of Approved Monitoring Technologies

The list of approved monitoring technologies should be expanded to include alternative periodic screening and continuous monitoring technologies.

Under proposed NSPS OOOOb and EG OOOOc[46], operators have the ability to use EPA approved alternative periodic screening or continuous monitoring technologies to satisfy the equipment leaks for well sites, centralized production facilities, and compressor stations. The Industry Trades have provided previous comments[47] on how to improve these proposed alternative technology provisions. Furthermore, results from alternative technology surveys could not be used for Subpart W emission calculations as proposed. Therefore:

- Operators would need to conduct an annual OGI or M21 survey for Subpart W for components subject to NSPS OOOOa/b/c or for other components if they elected to not use the population emission factors. This annual survey could be beyond what is required under NSPS.
- Results from use of alternate technology under NSPS OOOOb or EG OOOOc would be reported under large emissions release if thresholds were exceeded under Subpart W.

These two consequences would disincentive the use and development of alternate leak detection technologies. Therefore, 98.234(a) should be updated to include: “Periodic screening or continuous monitoring as specified in § 60.5398b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter…”

3.10.8 Component Applicability

The Industry Trades support EPA’s proposal to exempt “components in vacuum service” from the equipment leak provisions in 98.233(q) and (r). These components have been historically exempt from the NSPS leak detection standard since no fugitive leaks are expected. However, we do not support inclusion of reporting requirements that include reporting of component counts for components in vacuum service.

3.11 Other Large Release Events

The Industry Trades support inclusion of a category of other large release events in Subpart W reporting requirements because these sources have been observed across many basins, and literature has demonstrated that they can have an outsized impact on total emissions. However, both the threshold and triggers for inclusion of an event based on credible information are problematic. Furthermore, in many cases it will double count emissions reported elsewhere in the regulation.

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[46] Proposed § 60.5398b and § 60.5398c.

[47] The Industry Trades have provided previous comments on how to improve these proposed alternative technology provisions. See Comment 3.0. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428 https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-3819

3.11.1 Other Large Release Events Threshold

3.11.1.1 Instantaneous Rate of 100 kg/hr is Not a Meaningful Threshold

A threshold of an instantaneous rate of 100 kg/hr should be paired with a duration in order to ensure that the observation is, indeed, associated with a large release event. A measurement report of an instantaneous rate of 100 kg/hr should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event.

EPA explains that it "is proposing revisions to include reporting of additional emissions or emissions sources to address potential gaps in the total CH_4 emissions reported by facilities to subpart W."[48] "These revisions include proposing to add a new emissions source, referred to as ''other large release events,'' to capture large emission events that are not accurately accounted for using existing methods in subpart W."[49] An "other large release event" would be defined to include any event that exceeds an instantaneous methane emissions rate of 100 kg/hr or exceeds 250 mt CO_2e for the entire event.[50]

EPA further explains that the 250 mt CO_2e event-based threshold is based on a comparison to the Aliso Canyon event and other release scenarios that EPA considers to be objectively large. EPA asserts that the 100 kg/hr instantaneous emissions rate threshold is appropriate because it would "align with the super-emitter response program proposed in the NSPS OOOOb" and would "provide a means to get information for these large, shorter duration releases."[51]

The proposed reporting thresholds for "other large release events" are flawed for two reasons. First, EPA fails to provide any explanation of whether the reporting thresholds are appropriate or necessary for purposes of implementing the WEC. As explained above, the key purpose of the Proposed Rule is to provide information necessary for implementing the WEC. There are obvious questions that should be asked and answered by EPA as to how the type and scope of "other large release events" that would be required to be reported under the Proposed Rule squares with implementation of the WEC. EPA's views on the relationship between the proposed reporting thresholds and implementation of the WEC are necessary for EPA to fully assess the impact of the Proposed Rule and to allow for commenters to assess EPA's reasoning and provide informed input.

Since oil and gas emissions are highly variable in rate and duration, an instantaneous observation, even if extrapolated to provide results in units of an hourly emission rate as is typical, merely provides information regarding potential observations of far less than the represented hour in most cases. This is because an emission source with duration greater than 1 hour may have a variable rate over that hour or an emission source may resolve in far less than the hour. An instantaneous threshold of 100 kg/hr methane could result in numerous objectively small emission events (especially compared to an objectively large event release of at least 250 mtCO2e). An emission duration, assuming perfect observation and consistent emission rate of 1, 100, or even 1,000 times the <1 minute observation period for many technologies (assume 1

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[48] 88 Fed. Reg. at 50284.

[49] Id.

[50] Id. at 50296.

[51] Id. at 50296-7.

minute here), would result in emission event quantities of 0.05, 4, or 42 mtCO2e or 0.02%, 2%, or 17% of the corresponding 250 mtCO2e threshold. In fact, it would take nearly 5 days of a constant emission rate of 100 kg/hr to accumulate emissions of 250 mtCO2e, of which there is no reasonable extrapolation of an instantaneous remote sensing emissions event.

Therefore, an instantaneous rate of 100 kg/hr is not a meaningful threshold to indicate that an emission source is large or even otherwise unaccounted, since multiple intended and accounted for emissions have transient large emission rates (blow downs, drilling completions, liquid unloadings, etc.). Such data should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event. emissions.

3.11.1.2 *Other Large Release Threshold Needs to be Modified*

If Other Large Releases Remain in the Rule, Modify the Threshold

At a minimum, the Industry Trades recommend that EPA modify the threshold for this category in 98.233(y)(1)(i) as follows (and modifying 98.233(y)(1)(ii) as applicable):

(i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that~~either~~:

(A) Emits methane at any point in time at a rate of 100 kg/hr or greater; ~~or~~ **and**

(B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more.

Requiring both thresholds be met would catch large releases discussed in the proposed rule's TSD, such as well blowouts, while also easing the burden on reporters to assess relatively smaller emission events, such as PSV releases that occur over a few seconds to minutes.

If EPA does not change the threshold as recommended below, the Industry Trades recommend that a duration of 100 hours be paired with the instantaneous rate of 100 kg/hr, which is commensurate with a duration at that emission rate that would result in 250 mtCO2e of

3.11.2 Detection Technology Must be Approved by the Super-Emitter Response Program

Furthermore, the Industry Trades are requesting that EPA clarify that the rate of 100 kg/hr is determined with only advanced detection technology and third parties approved by EPA through the SERP in NSPS OOOOb and not based on presumptive calculations, models, or ground sensors which have varying levels of uncertainty. Furthermore, if industry is not approved to use the technology for compliance with OOOOa, OOOOb, or OOOOc, the technology should not be required to be used for reporting purposes under Subpart W and used to determine fees under the WEC. Requiring this will discourage voluntary monitoring by companies, discourage new technology development, and include potentially highly inaccurate data to be the basis of the WEC.

3.11.3 Other Large Release Events Duration

EPA is proposing that reporters must assume a leak duration of 182 days if the start time of an event cannot be determined based on "monitored process parameters." EPA has no basis for using 182 days.

As noted in the proposed rule's TSD, typical durations for large releases are several hours to several days. The Industry Trades believe this 182-day assumption is derived using average leak duration data including a significant statistical outlier event[52] that should be excluded from calculated averages, most notably because the time it took to resolve the leak was not due to lack of awareness of the leak, but rather the complexity of resolving the leak. Accordingly, the Industry Trades disagree with EPA's statement in the TSD that the duration should not be shorter than the Aliso Canyon event. Besides it being a known event, EPA is proposing a default leak duration even longer than that statistical outlier event (111 days vs. 180 days).

The Industry Trades recommend a duration of half the time since the last optical gas imaging inspection, or the time since operator inspection of the source in question (e.g., operator rounds that proactively include flare, thief hatch or other inspections), site level measurement campaign, continuous monitoring system, or other monitoring data, or a maximum of 30 days if no other data is available. The maximum duration of 30 days is a conservative estimate consistent with (a) EPA's acknowledgement in the TSD that "Studies on large releases from oil and gas facilities commonly report that these emissions are intermittent, with typical durations of several hours to several days (Chen *et al*., 2022; Wang *et al*., 2022)", and (b) that most well sites are expected to have operator rounds occurring more frequently than every 30 days and, further, the odds of a significant event going unnoticed by both and operator and 3rd parties (satellite, etc.) are unlikely.

Furthermore, the Industry Trades believe that additional clarification and flexibility needs to be provided for "monitored process parameters." This is particularly critical for very short emission events for which telemetry may not be available or reliable. The Industry Trades are concerned that any ambiguity around this requirement could result in vast over-reporting of emissions by assuming a duration of 182 days. Monitored process parameters are not defined in the rule, but in 98.236(y)(4) EPA says that this includes "pressure monitor, temperature monitor, other monitored process parameter (specify)." The Industry Trades recommend clarifying this by allowing reporters to use additional process parameters, such as site inspections, cameras on location, etc. that confirm the event duration.

3.11.4 Credible Information

EPA is proposing that operators must report emissions from other large release events if they have "credible information" that a large release event has occurred. The Industry Trades are concerned that requiring reporters to use all credible information, especially where credible information in this context is ill defined, may disincentivize voluntary monitoring with emergent technologies where leaks could be discovered, but may have a large range of uncertainty (generally associated quantitative emissions estimates and short observational periods of less than 1 minute). Paradoxically, the shorter duration measurements tend to have higher accuracy in quantification for the short duration and the longer duration measurements tend to have emission estimating uncertainties that can span orders of magnitude. The Industry Trades recommend that EPA define "credible information" in a way to allows operators to use regulatory-driven inspections, allow for additional parameter monitoring while accounting for telemetry malfunctions, site inspections or camera monitoring, and engineering estimates to determine if a release has occurred and is subject to reporting.

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[52] Underground storage station well blowout near Los Angeles, CA (i.e., Aliso Canyon) in 2015, event duration was 112 days as opposed to other events which were significantly shorter.

3.11.5 3rd Party Event Reporting

In 98.236(y), EPA is proposing that reporters must report any events identified through a potential super-emitter release. The Industry Trades urge EPA to implement guardrails around what and how a third-party could report, which is particularly impactful for those subject to SERP. Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality and accuracy of those reports (including, but not limited to, data integrity, completeness, free from atmospheric interference, timing or greatly delayed notification, etc.). While the industry strives for excellence in reducing large release events, resources which would otherwise be utilized to minimize emissions could be diverted to respond to large volumes of unfounded third-party notifications which may have no basis in reality.

The proposed requirement to consider third-party release reports is beyond EPA's authority.

Additionally, the **Industry Trades request EPA to clearly define the scope of credible information that would trigger additional investigative and reporting burdens**. The Industry Trades are concerned that unqualified third-party reports developed by unqualified operators could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear guidelines on who would be qualified to provide third-party reports and the associated duration of an observation necessary to trigger investigation and reporting obligations under Subpart W.

EPA proposes that third-party reports of "other large release events" submitted under NSPSSubparts OOOOb or OOOOc must be documented and addressed under Subpart W.[53] **API explained in its comments on the Subpart OOOOb and OOOOc proposed rules that EPA does not have authority to allow third parties to generate information that triggers regulatory requirements for affected/designated facilities.**[54] We incorporate by reference those comments here. Because the proposed third-party reporting requirements under Subparts OOOOb and OOOOc are beyond EPA's authority, those requirements should not be finalized and, by extension, should not be referenced or incorporated into the Subpart W provisions addressing "other large release events."

To begin, it is not possible to discern without further explanation from EPA who might constitute "another third party." That ambiguity makes it impossible to devise and submit informed comments on this aspect of the proposed reporting requirement.

Having said that, it is possible that EPA intends "another third party" to mean an entity submitting information to an affected facility outside of the third-party reporting provisions established under NSPS Subparts OOOOb or OOOOc. If that is the case, this aspect of the Proposed Rule is inadequate because EPA fails to explain the legal basis for imposing such requirements, including why such a requirement might be a reasonable under CAA § 114. Such a requirement would, in any event, be outside of EPA's CAA § 114 authority because CAA § 114 authorizes only EPA to collect information. It does not authorize EPA to impose a mandatory reporting obligation that would be triggered by third-party observations or

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[53] 88 Fed. Reg. at 50433.

[54] API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," EPA-HQ-OAR-2021-0317-2428 at 97-99.

assertions. If EPA believes that information about "other large release events" not reported pursuant to NSPS Subparts OOOOb or OOOOc should be reported by affected facilities, EPA must initiate the information request and may not rely on reports submitted by third parties.

Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality (including data integrity, completeness, free from atmospheric interference, timing of or significant delay in notification, etc.) and accuracy of third-party reports. The Industry Trades may submit supplemental comments after the Oct. 2 deadline.

At this time, the term "credible" is not defined in this rule. The Industry Trades recommend that EPA adopt the Industry Trades recommendations for SERP, and 98.236(y) is modified to only include events which EPA deemed credible under the SERP, and modify the citation below as follows:

> *(y) Other large release events. You must indicate whether there were any ~~other~~ credible large release events from your facility during the reporting year and indicate whether your facility was notified of a ~~potential~~ credible super-emitter release under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If there were any ~~other~~ credible large release events, you must report the total number of ~~other~~ large release events from your facility that occurred during the reporting year and, for each ~~other~~ credible large release event, report the information specified in paragraphs (y)(1) through (10) of this section. If you received a notification of a potential super-emitter release from a third-party for this facility or a super-emitter release notification under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.*

The Industry Trades are re-iterating our previously submitted comments regarding the credibility of those 3rd-parties reporting[55] as proposed in NSPS OOOOb. In short, the Industry Trades reiterate the importance that any third-party conducting these monitoring events should be certified by EPA to be included in the SERP.

In general, the Industry Trades are concerned that events reported under other source categories, such as "blowdowns," thief hatches or equipment leaks could inadvertently be double counted under other large release events. The Industry Trades requests that EPA codify clear guidance on how to ensure that information reported by a 3rd party can be appropriately subtracted from events that could reasonably be reported under another category.

3.11.6 Other Concerns Regarding Other Large Release Events

The Industry Trades request that EPA remove the latitude/longitude reporting requirement proposed in 98.236(y)(11)(iii), and instead allow county-level reporting for pipeline release events (consistent with PHMSA requirements). If EPA maintains the requirement to report latitude and longitude of the release event, the Industry Trades request that EPA clarify that these events at sites other than pipeline locations may consist of a single latitude/longitude for a site (and should not include the granular latitude and longitude of the individual component).

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[55] API Comments on NSPS OOOOb and EG OOOOc Supplemental Proposal letter, dated February 13, 2023. Section 1.1.

Furthermore, remote sensing technologies generally do not distinguish between emissions sources that are transient, included sources (blow downs, liquid unloadings, crankcase venting, etc.), or unintended sources that may or may not already be identified (unlit flares, over pressurized tanks, etc.) and thus there is a risk for double counting of certain emissions. Owner/operators should exclude sources that are already otherwise accounted for under another category, and EPA should explicitly allow exclusion of observations that could be classified as large emissions events but are otherwise already accounted for in another category.

To address one of EPA's requests for comments in the preamble, the Industry Trades believe that reconciling top-down data with bottom-up data should not force reporters to revise bottom-up estimates. The values recorded by these top-down sensors require significant data processing and analytics to provide the required measurement values, including concentration or flux. Moreover, even if the concentration (or concentration-pathlength) were perfectly accurate, error is introduced in post processing to produce estimates of emission rates, and these errors vary greatly depending on both the technology deployed, but even proprietary data treatment techniques between vendors of similar technologies. Beyond these uncertainties, however, is an inherent uncertainty introduced due to the temporal misalignment between the observational data and the bottom-up reporting methods. Not only do "matching" style reconciliation exercises require high spatial resolution of bottom-up emissions estimates (disaggregation to sites or even to the equipment level), but such exercises demand high temporal resolution. Otherwise, reliable extrapolation techniques must be applied to the often short duration observations to produce longer term emissions estimates. The aggregation of these uncertainties implies that the "top-down" measurements cannot be deemed more accurate, but simply useful in that they provide a different view of emissions.

3.12 Reporting Combustion Sources in Subpart C versus Subpart W

Emissions from natural gas combustion are *not* waste emissions that should be subject to the methane fee but are a result of the end use of natural gas within the value chain; emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations.

The Industry Trades appreciate that EPA intends to provide clarity on when reporters can use subpart C calculation methodologies instead of Subpart W, including defining the applicable gas quality. However, EPA has not provided sufficient information to justify the composition threshold of natural gas in determining between use of Subpart C or Subpart W calculation methodologies. EPA, in the TSD-W, concluded that the appropriate threshold criteria for use of subpart C includes a natural gas composition of 85% CH_4, but this threshold does not appear to represent any national or basin-wide average of the composition of fuel gas. EPA must provide additional information regarding the election of the 85% CH_4 composition threshold as a criteria for use of Subpart C methodologies.

As the Industry Trades previously commented during the June 2022 proposal, EPA should move all combustion calculations and reporting requirements from Subpart W to Subpart C to conform with the structure of the rule for other industries reported under the GHGRP. This would eliminate the current and proposed confusing structure that splits oil and gas combustion emissions across multiple subparts and references back and forth between the two subparts.

EPA seeks comment on "amending Subpart W to specify that all industry segments would be required to report their combustion emissions, including CH_4, under Subpart W to more accurately reflect the total

CH4 emissions from such facilities within the emissions reported under Subpart W." EPA asserts that Section 136(h) of the CAA specifies that EPA must "revise the requirements of subpart W…. [to] accurately reflect **the total CH_4 emissions and waste emissions** from the applicable facilities and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, **to demonstrate the extent to which a charge under subsection (c) is owed**" (emphasis added). Methane slip emissions from combustion are *not* waste emissions that are subject to the methane fee but are a result of the end use of natural gas within the value chain. Therefore, such emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations, when they are defined under future EPA rulemaking.

The IRA includes several statements that clarify the definitions of waste with regards to methane emissions within the rule. The IRA includes provisions for exemptions based on regulatory compliance with new source performance standards and state-level implementation of existing source rules that are equivalent or greater in emissions reductions to EPA's November 2021 Methane Rule framework. Neither the 2021 Methane Rule Framework nor the subsequent December 2022 proposal for NSPS OOOOb and EG OOOOc include source performance standards for methane slip from compressor engines. While not directly applicable to the methane fee, Section 50263 of the IRA clarifies that royalties on all extracted methane emissions on Federal lands and the Outer Continental Shelf have a stated exception for "gas used or consumed within the area of the lease, unit, or communitized area", which clearly would exempt the routine use of fuel gas, and associated methane slip emissions, from such royalty calculations. Considering these statutory provisions of the IRA, methane slip from compressor engines should not be included within the emission calculation framework for Subpart W and the eventual methane fee calculations that EPA will define at a later date.

3.13 Methane Slip from Incomplete Natural Gas Combustion

Direct measurement and the use of default equipment-specific destruction efficiencies should be allowed regardless of fuel type, and EPA should allow for control efficiencies from emerging technologies.

The Industry Trades agree with the agency that the default combustion efficiency for incomplete combustion or "methane slip" should be updated. However, it is important to note that the changes to methane combustion slip emission factors are expected to result in one of the largest changes to reported methane emissions, and EPA should allow the use of performance tests to determine methane slip factors regardless of fuel type. This would critically incentivize investments in technologies to reduce methane slip and would meet the objective of using empirical data. However, EPA should include these revisions under Subpart C instead of under Subpart W.

EPA's basis for exclusively using default equipment-specific destruction efficiencies, when the fuel does not meet at least 950 btu/scf, and contains less than 1% CO2 and at least 85% methane by volume is flawed. We recognize that EPA tried to simplify the performance test requirement to a one-time performance test, and as such did not propose to allow performance testing because fuel types "are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions." The Industry Trades make two comments on this assertion. First, operator experience indicates that field gas is not significantly variable year over year and EPA does not provide data to support its assertion. Second, EPA does not explain why the range of any expected variability would result in a change in combustion slip. Third, and most importantly, reporters commonly conduct performance testing on engines to meet NSPS JJJJ/NESHAP ZZZZ or state regulatory requirements. As such, EPA should allow reporters to use those results regardless of the fuel gas type, as well as the default equipment-specific combustion efficiency for reciprocating internal combustion engines (RICE) and gas turbines (GT), as long as the performance test results are only applied to sites with similar fuel gas quality.

To further emphasize the importance of allowing performance test data from any RICE or GT, the Zimmerle study cited by EPA is representative for natural gas compressor stations, but it does not include any smaller engines likely to be found in an upstream environment. Allowing directly measured data will both provide EPA with additional details regarding methane slip related to the smaller engines, and it will allow operators to use empirical data as aligned with EPA's intent. Critically, this will also incentivize operational improvements to reduce methane slip from natural gas combustion. This also clears up the proposed discrepancy where EPA proposes to mandate incorporation of performance test results for some RICE and GTs, but prohibits the use of performance test results for others. Ultimately, there is no reason EPA should not allow operators to use results from periodic performance tests conducted per EPA reference methods regardless of fuel quality.

The table below summarizes the distribution of combustion efficiencies calculated from member-provided performance tests:

Horsepower	Count	Minimum Combustion Efficiency	Mean Combustion Efficiency	Median Combustion Efficiency	Maximum Combustion Efficiency
> 500 hp	76	96.16%	98.29%	99.46%	99.46%
< 500 hp	57	98.29%	99.58%	99.99%	99.99%

The above data is based on performance tests using engine horsepower, load, break-specific fuel consumption, the average grams of methane per horsepower-hour over three test runs, and the methane concentration of fuel gas. The combustion efficiencies were derived by dividing the stack test mass of methane by the mass of methane consumed in the fuel gas. The results show that minimum stack test combustion efficiency for engines greater than 500 horsepower is on par with EPA's equipment-specific default combustion efficiency for 4 stroke lean burn engines; while the combustion efficiency for engines less than 500 horsepower is greater than EPA's equipment-specific combustion efficiency for the same engine type. The data illustrates how smaller engines typically have favorable combustion efficiencies given they have smaller cylinder bores. The Industry Trades believe that allowing operators to develop horsepower-specific destruction efficiencies based on performance tests would lead to more accuracy while meeting EPA's intent to measure combustion slip from internal combustion units.

EPA should also allow for flexibility to incorporate methane controls as new technologies are being developed to control methane emissions from RICE. The Industry Trades recommend that EPA add a methane control efficiency parameter to Equation W-39B to allow for flexibility of incorporating a control efficiency to enable reporters to report methane slip more accurately when methane control technologies emerge and are demonstrated to be effective.

Allowing for the use of additional approaches to calculate methane slip from compressor engines would further support technology development. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program (REMEDY | arpa-e.energy.gov) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in natural gas fired lean burn engines. If technology development from this 3-year, $35 million research program is successful, the ability to use updated values in methane emissions reporting could help to drive greater adoption of new technologies in operations.

3.14 Drilling Mud Degassing

In proposed Calculation Method 1, EPA is proposing to quantify drilling mud degassing by applying an emission rate derived from a representative well in the same sub-basin and at the "same approximate total depth." The Industry Trades request clarification on how to determine the "same approximate total depth."

EPA has proposed that operators must use mudlogging measurements taken during the reporting year, and therefore calculate emissions using Methodology 1. The Industry Trades disagree with this requirement, as it is possible a mudlogging measure is taken at the very early stages of a drilling operation, and that measurement may not ultimately be reflective of the entire duration of the drilling operation. The Industry Trades recommend allowing reporters to use Methodology 2 for all active drilling. The Industry Trades also propose a third option (see next comment), in the event that some mudlogging data is available.

The proposed third option would serve as a combination of the currently proposed Method 1 and 2. As stated above, this would allow operators to use a combination of the two methodologies when a varying level of directly measured data is available. In this third option, mudlogging measurements would be used based on Method 1 for the period in which the data is available, and Method 2 would be used for the remaining period of drilling activity where mudlogging data is not available. This method should also allow operators to account for drilling mud degassing vapors sent to a control device.

EPA is proposing to calculate emissions from drilling mud degassing based on the total time that drilling mud is circulated in the representative well. The Industry Trades request that EPA clarify that this should be calculated based on circulating time in the hydrocarbon bearing zones only (i.e., excluding surface holes drilled by a spudder rig when no hydrocarbons are present).

One further complication of the proposed method for quantifying methane emissions from drilling mud degassing is that the concentration of natural gas (or methane) in drilling mud is not currently specifically measured and is difficult to obtain. Further, it is not measured by mud loggers in units of ppm, as the measurement instrument used is in units that are not representative of methane concentration.

3.14.1 Proposed Calculation Method 2

EPA is proposing the following emission factors in MT CH4 per drilling day for drilling mud degassing: 0.2605 for water-based drilling muds, 0.0586 for oil-based drilling muds, and 0.0586 for synthetic drilling muds. The EPA based these factors on a study evaluating emissions from offshore drilling from 1977, which is both outdated, and not representative of most onshore drilling operations in the United States. Furthermore, these outdated factors are based on mud throughput, but the basis remains unclear. The Industry Trades reiterate that the emission factors compiled in the 2021 API Compendium for Well Drilling and mud degassing (Section 6.2) is appropriate for the well bore and porosity conditions for onshore drilling operations as it was developed specifically for onshore operations. Use of the proposed offshore emission factors for onshore drilling operations will significantly overstate methane emissions from onshore production mud degassing. The Industry Trades suggest that the emission factor should be derived as a function of well dimensions to better represent mud degassing emissions. Otherwise, the Industry Trades recommends that proposed methodology 2 be revised based on drilling time in hydrocarbon hole section, and not overall event days. There can be multiple days in a hydrocarbon hole section where the pumps are not circulating.

3.14.2 Reporting Requirements

Reporting requirements proposed in 98.236(dd) require reporting total vertical depth of the well, and the circulation time of the drilling mud within the wellbore. The Industry Trades do not support reporting this information, as EPA did not address why the information would be requested. Furthermore, total vertical depth would not provide representative information for horizontal wells and would not improve the reported data quality.

3.15 Crankcase Venting

In general, the Industry Trades support the use of actual test data for crankcase venting when available, while still allowing the use of a provided emission factor. However, the Industry Trades believe the emission factor for this activity should be derived based on horsepower in order to be more reflective of operations in the onshore production or gathering and boosting segments, should include the ability to take credit for routing the emissions to a control device, and do not believe this emission source category should include gas turbines. The study cited in the TSD included an audit of three gas compressor stations and two natural gas storage sites[56]. These facilities are expected to have a much higher vent rate than in production operations due to the larger engine size required in gas compressor stations and gas storage. Therefore, the proposed average emission factor may reflect an overestimation of this source for upstream production and many smaller gathering and boosting facilities. The Industry Trades suggest that EPA considers deriving an emission factor based on engine horsepower instead of vent count, as the vent rate is correlated with engine size rather than number of vents.

As proposed, there is no method to reflect reductions if emission controls are developed and implemented or crankcase venting is routed to a control or combustion device. The Industry Trades recommend adding this flexibility by including a control efficiency parameter in Equation W-45, which also has the added impact of incentivizing controls where feasible.

The Industry Trades also recommend that EPA provide clarification around how to account for crankcase vents which are manifolded together, as the reporting requirements are on a per-vent basis.

EPA is proposing a reporting requirement for the average operating hours for each reciprocating internal combustion engine or gas turbine. The Industry Trades recommend the removal of this “average” data; it is duplicative and requires operators to average numbers used in calculations for the sole purpose of reporting this element. The Industry Trades recommend removing this data reporting requirement or leaving the reporting requirement on a per-site basis of total operating hours.

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[56] Johnson *et al.*, 2015

Additionally, the factor prescribed by EPA is based on an API study,[57] which only represents reciprocating engines, and not natural gas turbines. The study's definition of crank case is, "The crank case on *reciprocating engines* and compressors houses the crank shaft and associated parts, and typically an oil supply to lubricate the crank shaft…"[58] (emphasis added). The study also only referred to reciprocating engines later in the document, "Additionally, *reciprocating engines* crankcase vents were checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) because blow-by reduces cylinder compression that causes inefficient operation and contributes to unburned and partially burned fuel emissions[59]" (emphasis added). There is no mention anywhere that natural gas turbines were evaluated as a part of this study.

Since the definition of crankcase within this study explicitly states that it is only applicable to reciprocating engines, and the body of the text supports that definition, then natural gas turbine crankcase vents were not evaluated as part of this study. It is arbitrary to use 2.28 scf/h per crankcase vent for natural gas turbines because turbines were not evaluated for this study.

Natural gas turbines are inherently different from reciprocating engines and quantifying crankcase venting in the manner proposed does not make sense.

A reciprocating engine is a cyclic operation by nature - the piston is required to stroke back and forth inside the cylinder to complete four primary process strokes: intake, compression, power, and exhaust. The piston moves back and forth inside the cylinder of a reciprocating engine, using the piston rings to seal process gas inside the cylinder during the combustion process. This piston is connected to the crankshaft, which translates the reciprocating movement from the combustion in the cylinder to rotational movement at the output shaft. Any leakage across the piston rings will result in combustion gas in the crankcase, which needs to be vented to avoid condensation, contamination, and ongoing reliability concerns. The piston rings act as a primary seal between the combustion process and the atmosphere, and the crankcase takes on the role of a rudimentary "capture" system.

Gas turbines operate using a completely different mechanical method. There is no cyclic or reciprocating element to a gas turbine operation (no piston, piston rings, or crankcase). A gas turbine uses one (or more) rotating shafts to continuously complete all four primary combustion functions inside the gas turbine casing: intake, compression, combustion, and expansion. Since the shaft(s) are already rotating as part of the combustion process, there is no requirement to have a translation from reciprocating to rotational movement, so there is no crankshaft or crank casing to be vented. Combustion gases are ultimately routed to the atmosphere by way of the exhaust duct once the power turbine has extracted the energy. The potential leakage points for combustion gases would be at the turbine casing flanged connections or at the shaft seals, which are addressed by other parts of this rulemaking (fugitive emissions).

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[57] Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites. EPA Phase II Aggregate Site Report prepared for U.S. EPA Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc. March 2006. Available at https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[58] Page 14 of 74 of API study.

[59] Page 40 of 74 of API study.

The Industry Trades propose that natural gas turbines not be included for reporting crankcase venting, as there are no crankcase vents on the natural gas turbines.

3.16 Gathering and Boosting versus Production Site Categorization

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves designation of upstream operators' centralized tank batteries that EPA has named "centralized oil production sites." These are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility." In the proposed rule, EPA has classified centralized oil production sites under the gathering and boosting segment.

The Trades appreciate that EPA has recognized centralized production sites as a facility type in the proposed rule. However, there are challenges and environmental disincentives with including "centralized oil production sites" in the gathering and boosting segment, especially when viewed through the lens of the upcoming waste emissions charge.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the gathering and boosting segment. These sites perform many of the same functions as the traditional well pad only production facilities (which are included in production), but reduce the overall environmental footprint associated with oil and gas development included emissions reductions and minimizing surface use by flowing multiple wells into on pad.

Next, EPA's proposed definitions are contrary to IRA's MERP waste emissions thresholds, where gathering and boosting sites are considered "non-production." In the MERP language, (f) Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production." The Gathering and Boosting segment (segment #8) is explicitly listed under "Non-Production." Clearly Congress did not intend for sites associated with production, such as "centralized production sites" to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the gathering and boosting segment in the past but for application of the fee, these sites should be considered production. Doing otherwise would result in an inequitable application of the fee that would most likely not be applied uniformly by all upstream operators.

EPA's proposal to group its proposed new definition of "centralized oil production site" within the "gathering and boosting" category, *see* 88 Fed. Reg. at 50,437/1, is inconsistent with the text and structure of CAA § 136. Congress defined "production" and "gathering and boosting" as two distinct items in a list of eight parallel categories of applicable facilities subject to the MERP charge, CAA § 136(d)(2) ("Onshore petroleum and natural gas production"), (8) ("Onshore petroleum and natural gas gathering and boosting"). EPA is therefore acting contradictory to this text and to Congress's intent when it proposes to categorize *production* facilities as *gathering and boosting* ones. And this mis-categorization will have consequences, because the waste emissions threshold above which a charge will be imposed on applicable facilities' emissions differs between these two categories, *see id.* § 136(f)(1), (2

The proposed definition of "centralized oil production site" is also inconsistent with the proposed definition and regulatory treatment of a "centralized production facility" in the pending CAA § 111 methane standards proposal for both new and existing sources.

In addition, the categorization of a centralized production site into gathering and boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane fees that may accompany categorizing production sites as gathering and boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installation dramatically increasing the amount of equipment in the field, increasing GHG emissions, and increasing surface use.

Further, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to “production supportive facilities.” Many operators have migrated to more centralized production facilities in an effort to reduce the overall environmental footprint. As opposed to midstream operators that traditionally operate gathering and boosting sites downstream of a custody transfer meter that are typically large compressor stations that boost gas across an area, the sites in question are a less impactful way of separating and storing fluids from multiple wells and providing efficient compression for artificial lift. Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment typically results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, are considered in the industry as part of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as “associated with a single well pad” this has created a great deal of confusion with reporters and centralized tank batteries have been categorized differently both by individual owners / operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb/c regulations, the “centralized oil production facilities” (referred to in NSPS OOOOb as “centralized production facilities”) are grouped under the production segment by definition, not gathering and boosting as explained below:

> *Currently, in Subpart W “Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236.”*

While NSPS OOOOb/c has a different name and definition of this as follows:

> *“Centralized production facility” means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage*

> *vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."*

In addition, in the Pipeline and Hazardous Material Safety Administration's ('PHMSA") proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate any production facilities as "gathering and boosting." Specifically, as defined in API's Recommended Practice-80 and incorporated in 49 CFR 192:

> *"The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. 'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."*

Both the NSPS OOOOb/c and PHMSA's name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. To mitigate confusion and create more rule alignment, the Industry Trades suggest that EPA align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/c.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal,

> *"as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." Also, the Trades note that even though EPA uses the word "gather" in the definition in Quad Ob/c, these sites are still properly defined as "part of the producing operations."*

Further, the fact that EPA has proposed the definition of "centralized production sites" as sites that do not include compressors that are part of the gathering and boosting segment is puzzling. If these sites are part of the gathering and boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the gathering and boosting segment on them? This demonstrates that EPA possibly does understand the distinction between gathering and boosting compressors that should appropriately be included in the gathering and boosting segment and centralized tank batteries that clearly should not.

As such, The Industry Trades request that EPA change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production (not gathering and boosting) for consistency and to reflect how the industry owns and operates these facilities. The Trades also strongly recommend that EPA delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

3.17 Need for EPA to Include Pathways for Other Types of Empirical Data

For many source categories under Subpart W, the Trade Industries appreciate that EPA has included several options for operators to be able to provide empirical data, such as measurement with metering or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. As API shared with EPA during the NSPS OOOOb and OOOOc rulemaking, many operators have included these technologies in their voluntary methane management programs, including the use of quantitative aerial technologies at more than 8,000 sites. Many of these systems provide quantitative information that, when paired with other operational sources of data, provide empirical information about methane emissions from assets. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. **A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.**

4. Administrative Recommendations

4.1 Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors

Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.

1. EPA should provide industry with a draft of the eGGRT form for review ahead of the reporting season (prior to January 1, 2026). The Industry Trades are concerned that the site-by-site reporting could cause these files to become very large and difficult to transmit and/or store.
2. EPA has not indicated how Best Available Monitoring Methods (BAMM) will be allowed for the newly proposed sources. The Industry Trades reiterates the need for ample implementation time.
3. Remove all requirements to report a count of equipment or events when there is a requirement to report on an equipment- or site-level basis. Requiring a count of an item that is already provided on a line-by-line basis does not improve the reported data quality, does not increase EPA's ability to validate the reported data, and introduces potential errors that will flag unnecessary follow between reporters and EPA.
4. Remove or automate Table AA.1.ii on Tab (aa)(1). All the required information is reported in Table AA.1.iii. By repeating this information in Table AA.1.iii, it increases the possibility of data errors while not improving data transparency.
5. Remove detailed reporting elements on Tab (aa)(1) in Table A.1.iii, as the detailed information on a well-by-well basis is already included on the respective source tabs (and proposed additional sources as part of this rulemaking):
    a. Well venting for liquids unloading;
    b. Completions or workovers with hydraulic fracturing;
    c. Completions or workovers without hydraulic fracturing;

    d. Well testing; and
    e. Associated gas venting and flaring.
6. Miscellaneous Topics
    a. Reporting condensate separate from other hydrocarbon products will be challenging due to where and how it is separated.

5. Rule Implementation

EPAs plans to finalize the rule in August 2024, with an implementation date of January 1st, 2025. The impractical tight timeframe to implement the final rule places an unrealistic expectation on reporters, especially given that (as proposed) they will have to install new equipment and develop inspection programs to comply with the rule. The impracticality of the proposed timeline is further exacerbated by the persistent supply chain shortages operators are experiencing for critical equipment necessary to comply with the proposed NSPS OOOOb, as the Industry Trades have described to EPA.[60] Primarily, the Industry Trades reiterates its position that measurement, sampling and monitoring requirements should not be included in the GHGRP itself. However, should any measurement, sampling and monitoring requirements be codified in Subpart W for sources not required to comply with other regulatory programs, EPA should allow for a phase-in period (as it did during the first two years of Subpart W implementation) to allow for reporters to incorporate those requirements.

6. Conclusion

The undersigned associations, representing the oil and natural gas industry, appreciate EPA's willingness to collaboratively engage with the regulated community in order to improve the quality and consistency of reported data while also streamlining the reporting process. The comments provided in this letter are intended to support this effort by providing EPA with additional context and potential unintended consequences associated with some of the proposed measurement, reporting, recordkeeping, and quality assurance/quality control requirements.

The Industry Trades support the goal of reducing GHG emissions across the value chain of the oil and natural gas industry, and it is critical that the EPA and the GHGRP reflect accurate reporting of GHG emissions. To that extent, it is important that EPA carefully consider these proposed revisions and new subparts and consider the points outlined by the Industry Trades while considering future proposed rulemaking.

The undersigned associations encourage EPA to carefully consider the comments and recommendations contained within this letter. We stand ready to respond to any questions and provide further clarifications, as needed, from EPA. Please do not hesitate to contact any of the undersigned or API's Jose Godoy, Climate & ESG Policy Advisor, at godoyj@api.org.

Sincerely,

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[60] https://www.api.org/news-policy-and-issues/letters-or-comments/2023/09/20/API-Letter-to-EPA-Administrator-Regan-on-EPA-Methane-Rule.

Aaron Padilla

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Vice President, Corporate Policy
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Angie Burckhalter

Angie Burckhalter
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The Petroleum Alliance of Oklahoma

Leslie Bellas

Leslie Bellas
Vice President
American Fuel & Petrochemical Manufacturers

CC: Chris Grundler, Director for Office of Atmospheric Programs, EPA
Mark DeFigueiredo, Office of Atmospheric Programs, EPA

Docket ID No. EPA-HQ-OAR-2023-0234
October 2, 2023

ANNEX A: API Study, "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States.

Note: Data for this study is included separately within this docket in excel format.

Memorandum

Date: July 2, 2020

To: Mark DeFigueiredo, Melissa Weitz, Adam Eisele

Climate Change Division, U.S. Environmental Protection Agency

From: Karin Ritter, Manager, Corporate Policy, American Petroleum Institute

Re: American Petroleum Institute Pneumatic Controller Measurement Study

The American Petroleum Institute (API) is pleased to provide the results of the API Field Measurement Study of Pneumatic Controllers and API's proposal for a two-tiered emission factor for controllers. Paul Tupper (Shell), on behalf of API, presented preliminary information from this study at the Stakeholder Workshop on GHG Data for Natural Gas and Petroleum Systems held in Pittsburg PA on November 7, 2019. This was followed with an API and EPA conference call on January 13, 2020 where API provided answers to EPA's questions regarding the study results and details (attached).

As a reminder, the API field study found that the average emission rate for properly functioning intermittent controllers was 0.28 scfh, 24.1 scfh for malfunctioning intermittent controllers and an overall average emission rate for all intermittent controllers of 9.3 scfh. Continuous low bleed controllers had an average emission rate of 2.6 scfh and continuous high bleed controllers 16.4 scfh. Malfunctioning intermittent pneumatic controllers measured in the API study account for about 85% of observed pneumatic controller emissions, from all controllers measured, and 98% of the observed intermittent pneumatic controller emissions. About 38% of the intermittent pneumatic controllers in the study were determined to be malfunctioning although a small subset of the malfunctioning controllers contributed the bulk of measured emissions.

The results of the API field study pneumatic controller measurements are consistent with prior studies (Allen et al. 2015, Thoma et al. 2017) which found that a small number of malfunctioning intermittent controllers accounted for the bulk of pneumatic controller emissions measured. Based on the results of the API study, API proposes that EPA modify 40 CFR Part 98 Subpart W to include a two-tier intermittent pneumatic controller emission factor option for intermittent pneumatic controllers that are included in a qualified inspection and repair program. This would be similar to the leaker emission factor option currently in Subpart W for equipment leaks. Specifically, API is proposing a properly functioning intermittent pneumatic controller whole gas emission factor of 0.28 scfh, and a malfunctioning intermittent pneumatic controller emission factor of 24.1 scfh. These emission factors would be applied to intermittent pneumatic controllers included in a qualified inspection and repair program. Intermittent pneumatic controllers not included in a qualified inspection and repair program would continue to use the current emission factor of 13.5 scfh. A qualified inspection and repair program would require instrument (optical gas imaging (OGI)) inspection of intermittent pneumatic controllers on a minimum annual frequency to determine whether they have continuous emissions which would indicate that they are malfunctioning. The tiered emission factor could be used by operators that voluntarily include intermittent pneumatic controllers in an inspection and repair program or that are required to include them by regulation or other requirement. Such an approach would enable demonstration of emission reductions by operators who are voluntarily conducting pneumatic controller inspections and repair and potentially incentivize further voluntary inspections to identify malfunctioning pneumatic controllers. It would also improve the accuracy of emissions reported into the Greenhouse Gas Reporting program for intermittent pneumatic controllers and ultimately could be used to improve the accuracy of estimated emissions in the Greenhouse Gas inventory. API is not proposing any changes to the emission factors for continuous bleed controllers at this time.

API notes that OGI inspection of intermittent pneumatic controllers to determine if they are properly functioning or malfunctioning is the technique used by EPA and the Colorado Department of Public Health and Environment (CDPHE) in their recently published study "Understanding oil and gas pneumatic controllers in the Denver–Julesburg basin using optical gas imaging". API also suggests that EPA may wish to include data from prior studies (Allen et al. 2015, Thoma et al. 2017) to calculate a set of tiered emission factors from a wider dataset.

Enclosed with this memo are an API paper titled "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States", an excel file with data tables for the study, and API's responses to EPA's questions received prior to the January 13, 2020 conference call. Should you have any questions regarding this study or API's tiered emission factor proposal please feel free to contact me.

Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States

Introduction

EPA's current Greenhouse Gas Reporting Program (GHGRP) emission factor for natural gas-driven intermittent vent pneumatic controllers represents an average emission rate of 19 pneumatic controllers, 7 measured in the US and 12 measured in Canada during two field campaigns in the 1990's (EPA, 1996). The 7 US pneumatic controllers had an average emission rate of 21.3 standard cubic feet per hour (SCFH) with a range of 8.8 to 39.6 SCFH. The 12 Canadian pneumatic controllers had an average emission rate of 8.8 SCFH with a range of 0.5 to 29.0 SCFH. Combined, these 19 intermittent pneumatic controllers had an average emission rate per intermittent pneumatic controller of 13.5 SCFH. The small total sample size (19 measurements) and high variability of the measurements suggests that the EPA mandated average emission factor of 13.5 SCFH warrants reevaluation.

Several pneumatic controller emissions studies conducted since then have focused on emission factor development or comparisons with existing factors based on field observations (Allen et al. 2013, Allen et al. 2015, Thoma et al. 2017, Prasino Group 2013). These studies observed a skewed distribution of emissions largely related to emissions from intermittent pneumatic controllers with higher than expected emissions for properly functioning controllers. Allen et al. (2015) found that 95% of observed emissions were attributable to 19% of pneumatic controllers and noted that the majority of the 40 highest emitting controllers were behaving in a manner inconsistent with manufacturer design. Thoma et al. (2017) also concluded that emissions were dominated by malfunctioning pneumatic controller systems, although the absolute emission rates observed were lower than with Allen et al.

The American Petroleum Institute (API) conducted a pneumatic controller measurement study between June and April 2016. Study goals included creating a pneumatic controller inventory for the regions surveyed, classifying pneumatic controllers, understanding the frequency of pneumatic controller malfunctions, and quantitatively measuring emission rates. The analysis presented in this report focuses on the quantitative measurements of intermittent vent pneumatic controllers, where the controllers are sub-classified as either properly functioning or malfunctioning intermittent pneumatic controllers. Emission factors are derived by sub-category, akin to the leak emission factor for fugitive components (US EPA, 2017). Overall, malfunctioning intermittent vent pneumatic controllers measured in the API study account for about 85% of observed pneumatic controller emissions and 98% of the observed intermittent vent pneumatic controller emissions.

Materials and Methods

Pneumatic Controller Inventory

Pneumatic controllers were inventoried at 67 sites[1] operated by 8 companies, across a variety of site types in the production and gathering and boosting segments of the oil and natural gas sector. The sites represented a variety of production and formation types, including conventional and unconventional oil and gas plays, across four basins as defined by the American Association of Petroleum Geologists (AAPG): Anadarko (AAPG Basin 360), San Juan (AAPG Basin 580), Gulf Coast (AAPG Basin 220), and Permian (AAPG Basin 430). Pneumatic controllers from these sites were inventoried and classified as either continuous high bleed, continuous low bleed, or intermittent vent pneumatic controllers based upon a combination of manufacturer information, manufacturer technical data sheets, and expert judgement.

Pneumatic Controller Emissions Measurements

Emission rate measurements were collected for controllers at 39 of the 40 sites with natural gas powered pneumatic controllers. For each measured pneumatic controller, the emission rate of whole gas was quantified using a high-volume sampler instrument (see description below). Whole gas emission rates were calculated based upon concentration, flow and equipment-specific hydrocarbon response factors developed from site-specific gas compositions, as provided by participant companies. In some cases, site-specific gas compositions were unavailable. AAPG basin average concentrations were developed from the available site-specific concentrations and applied to those sites in the same basin without site-specific gas concentrations.

Development of the specific instrument configuration and gas composition correction factors were recently described and applied in a companion study that compared the effectiveness of Method 21 and Optical Gas Imaging for monitoring of fugitive components in oil and natural gas operations (Pacsi et. al, 2019). In this study, a custom GHD recording high volume sampler, developed by GHD – the contractor preforming this study, was used for most pneumatic controller measurements. The GHD recording high flow sampler is a modification to the original high flow samplers developed by Indaco. These modifications include the use of a data logger to record the sample flow and the sample gas concentration at approximately 1/2Hz. Due to instrument availability, there were 8 instances where an Indaco high volume sampler was used for the pneumatic controller measurement and one instance where the Bacharach high volume sampler was used. Three of the 9, measured with the Indaco or Bacharach high volume samplers, had zero measured emissions, while the remaining six measured constant emission rates.

Sampling, over an approximate 15-minute period, occurred through a nozzle affixed to a sampling bag. The sampling bag was fitted over the emission point of the pneumatic controller allowing ambient air to comingle with the source emissions. The recording high volume sampler was equipped with a pump which pumped ambient air and hydrocarbons from the emission point through the nozzle to the flow

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[1] Five sites in the Permian Basin were not inventoried due to being primarily CO_2 or instrument air for the pneumatic controller supply gas.

meter and concentration detection instrument. The combustible gas concentration instrument, a Bascom-Tuner Gas Rover, measured combustible gas concentrations via one of two detectors: either a combination catalytic oxidation (0-5% hydrocarbon gas) or a thermal conductivity (5-100% hydrocarbon gas) detector. Further information on the instrument detail is available in the Supplemental Information from the companion equipment leaks study (Pacsi et. al, 2019) and references such as Lamb et al. (2015) and Thoma et al. (2017).

Properly functioning intermittent vent pneumatic controllers have near-zero emission rates between actuation cycles. Also, the volume of vented gas associated with controller actuations can vary widely from pneumatic controller to pneumatic controller. With the wide variation of emissions and high frequency of non-detect measurements in this and prior pneumatic controller measurement studies, it was prudent to develop a conservative field detection limit estimate for this study to facilitate appropriate interpretation of zero or near zero field measurements. The instrument methane detection limit for the GHD recording high volume sampler was determined to be 0.009 SCFH based on the lowest flow recorded during pneumatic controller testing and the methane detection limit of the Bascom-Turner Gas Rover (50 ppm) used in the GHD recording high volume sampler. However, in field use the instrument resolution was coarser than the instrument's minimum detection limit.

The GHD recording high volume sampler instrument operates with variable flow rates. Accordingly, the instrument detection thresholds and instrument resolution varied over the course of the study in terms of resolvable emissions rates since both the emission rate detection limit and instrument resolution is a function of measurement flow rate. An effective resolution for each non-zero time series was calculated as the minimum of the absolute value of the differences between adjacent elements of a given time series. This represents the minimum measured emission rate difference from one measurement to the next in each time series. The derived minimum effective resolution provided an estimate of the minimum resolvable emission rate for this study.

Figure 1 shows the effective resolutions for 127 of the time series measurements (non-zero time series for intermittent vent pneumatic controllers that varied over the course of the approximately 15 minute measurement). The median value of effective resolution for the 127 time series measurements is 0.26 SCFH, with approximately 70% of the measurements having an effective resolution between 0.2 and 0.35 SCFH. Therefore, an effective resolution over the course of the study was empirically determined to be 0.26 SCFH.

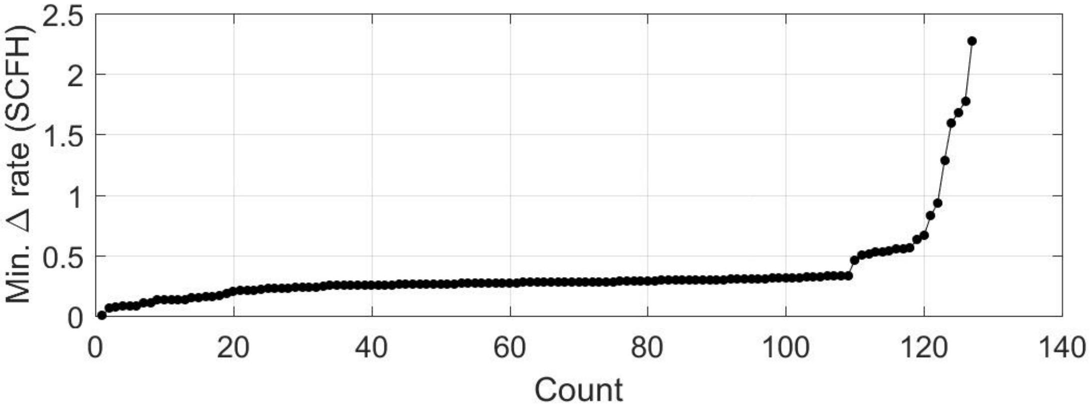


Figure 1: Instrument resolution step sizes for the recorded time series.

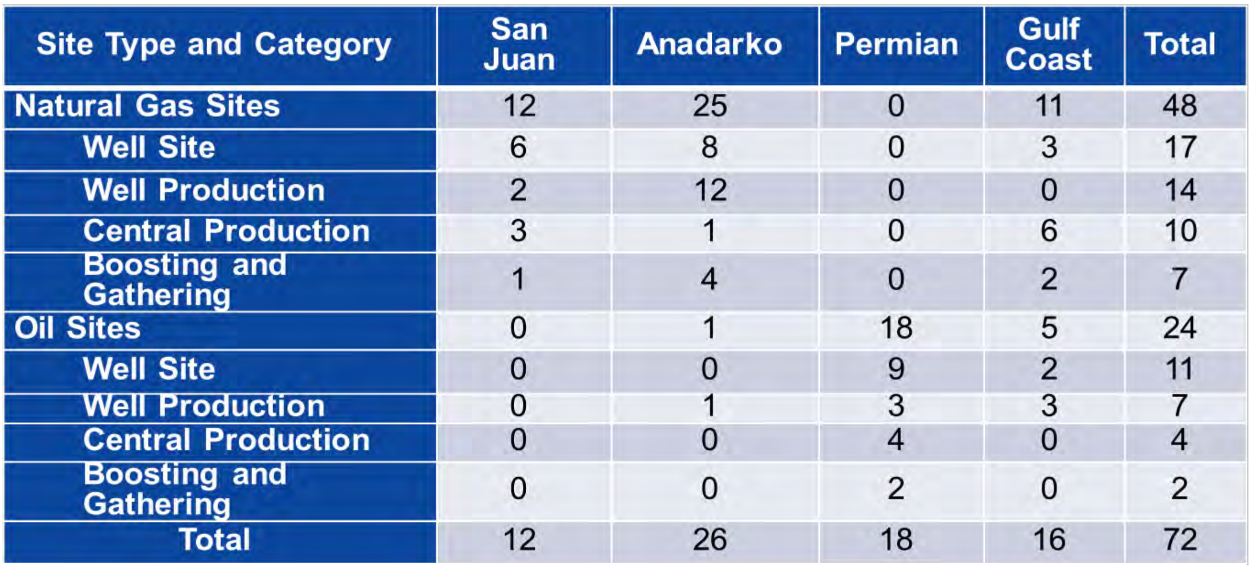
Approximately 45% of measured emission rate values of the intermittent vent pneumatic controllers were less than half of the effective resolution, and a large number had zero measured emissions. Thoma et al. (2017) previously described a “seepage rate” assumed to be on the order of 0.05 SCFH from properly functioning intermittent vent pneumatic controllers due to the practical limitations of metal to metal seals under real world conditions. Accordingly, low level emissions could have been occurring during field measurements in this campaign although the instrument recorded a low or zero value due to instrument resolution limitations.

Therefore, measured emission data points below half the effective resolution of 0.26 SCFH were conservatively assumed to be 0.13 SCFH. Thus, the minimum instantaneous emission rate within any intermittent vent pneumatic controller emission rate time series was assumed to be 0.13 SCFH for all analyses. In addition, an actuation was assumed to have taken place where the instantaneous emission rate exceeded 0.39 SCFH, indicating a clear episodic emission larger than 1.5 times the effective resolution and thus distinguishable from noise (actuation threshold).

Pneumatic Controller Inventory and Classification

A total of 72 sites were selected for the study. Table 1 tabulates the distribution of site type and category by basin.

Table 1: Site type and category for the four sampled basins*



Site Type and Category	San Juan	Anadarko	Permian	Gulf Coast	Total
Natural Gas Sites	12	25	0	11	48
Well Site	6	8	0	3	17
Well Production	2	12	0	0	14
Central Production	3	1	0	6	10
Boosting and Gathering	1	4	0	2	7
Oil Sites	0	1	18	5	24
Well Site	0	0	9	2	11
Well Production	0	1	3	3	7
Central Production	0	0	4	0	4
Boosting and Gathering	0	0	2	0	2
Total	12	26	18	16	72

*For a complete description of the site categories see: Table S1 of Pacsi, AP, et al. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth, 7: 29. DOI: https://doi.org/10.1525/elementa.368

Controllers at 67 sites were inventoried, including 45 with pneumatic controllers present and 19 sites without non-mechanical controllers. Of the 45 sites with pneumatic controllers present, 40 sites had one or more pneumatic controller powered by natural gas[2], four sites had pneumatic controllers exclusively powered by CO_2 and one site had pneumatic controllers exclusively powered by air. Detailed inventories of the controllers at the 45 sites with pneumatic controllers resulted in the identification of 420 controllers. The set of 420 controllers included 370 powered by natural gas, 39 powered by air or CO_2, seven powered electrically, and four out-of-service or with unknown power source. The natural gas powered pneumatic controllers were further classified into the three EPA categories (US EPA, 2014a): 1) intermittent vent; 2) continuous low bleed (<=6 SCFH) or 3) continuous high bleed (>6 SCFH) pneumatic controllers. Pneumatic controllers lacking sufficient detail to classify between intermittent or continuous service were labeled as "unclassified" (Figure 2).

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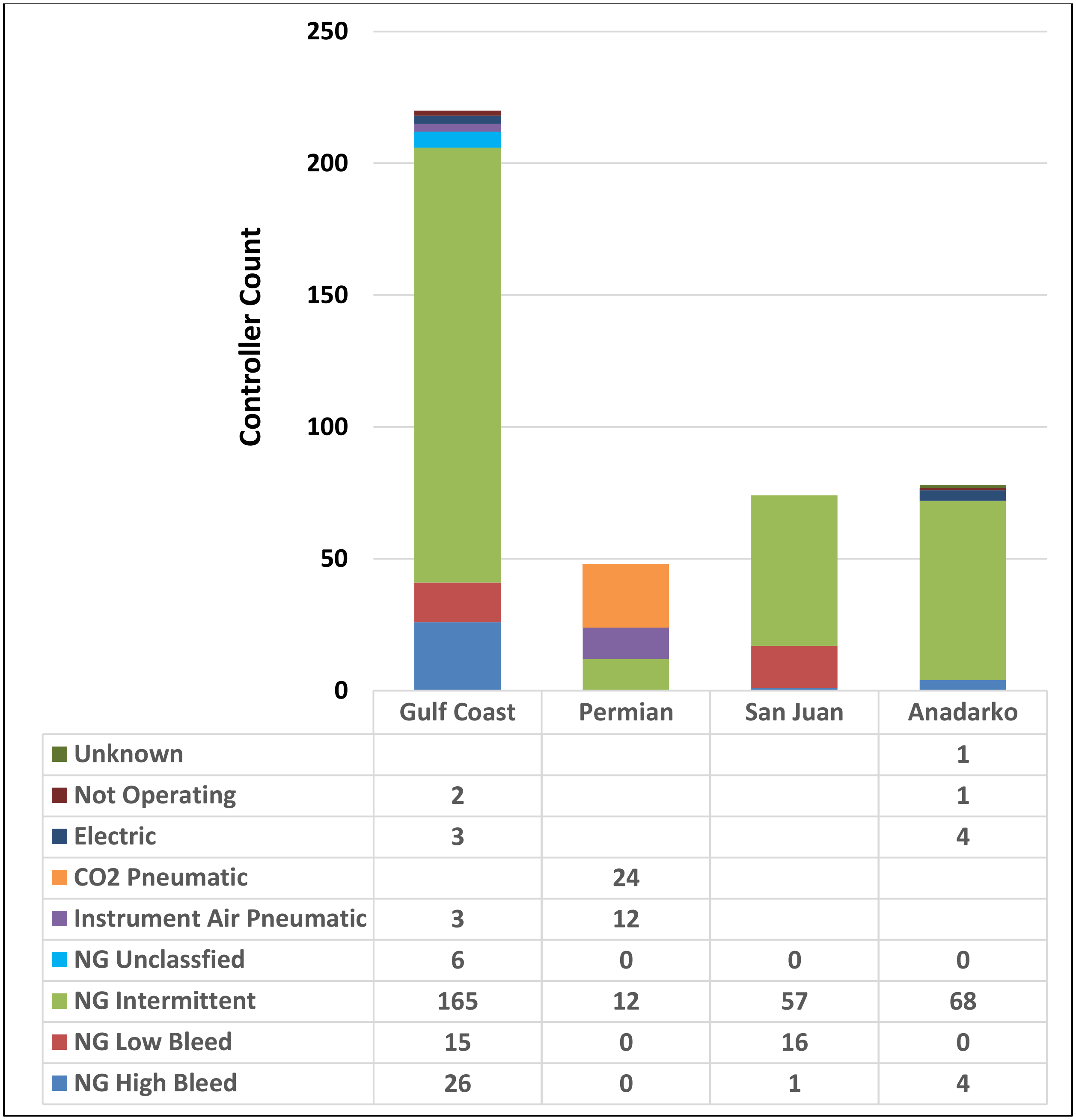
[2] Natural gas in the context of this study is inclusive of field gas, sales gas, processed gas, and other types of predominantly methane gas. The term excludes gas streams that were predominantly CO_2 or compressed air.



	Gulf Coast	Permian	San Juan	Anadarko
■ Unknown				1
■ Not Operating	2			1
■ Electric	3			4
■ CO2 Pneumatic		24		
■ Instrument Air Pneumatic	3	12		
■ NG Unclassfied	6	0	0	0
■ NG Intermittent	165	12	57	68
■ NG Low Bleed	15	0	16	0
■ NG High Bleed	26	0	1	4

Figure 2: Inventory of pneumatic controller types by basin.

The majority of inventoried natural gas-powered controllers were intermittent vent controllers. as shown in Figure 2. The Permian basin sites in this study generally used either mechanical, instrument air or CO_2 operated pneumatic controllers, resulting in a small number of natural gas-powered pneumatic controllers at those sites.

Pneumatic Controller Emission Measurements

Project time constraints only allowed for emission measurements on a subset of inventoried controllers. Exhaust emissions were measured from 308 natural gas powered pneumatic controllers at 39 sites. The vast majority of measurements were conducted using a GHD recording high-flow type instrument with readings predominantly captured at about two second sample rates over a measurement period of approximately 15 minutes. Controller meta-data was collected for each pneumatic controller measured. The meta-data included manufacturer, model number, type, service and photos. Each controller measured was classified into one of the US EPA's regulatory types: intermittent vent, continuous vent low-bleed bleed, or continuous vent high-bleed. The majority (85%) of the pneumatic controllers measured were intermittent vent type which is broadly consistent with the overall inventory for this study as shown in Figure 3. [3]

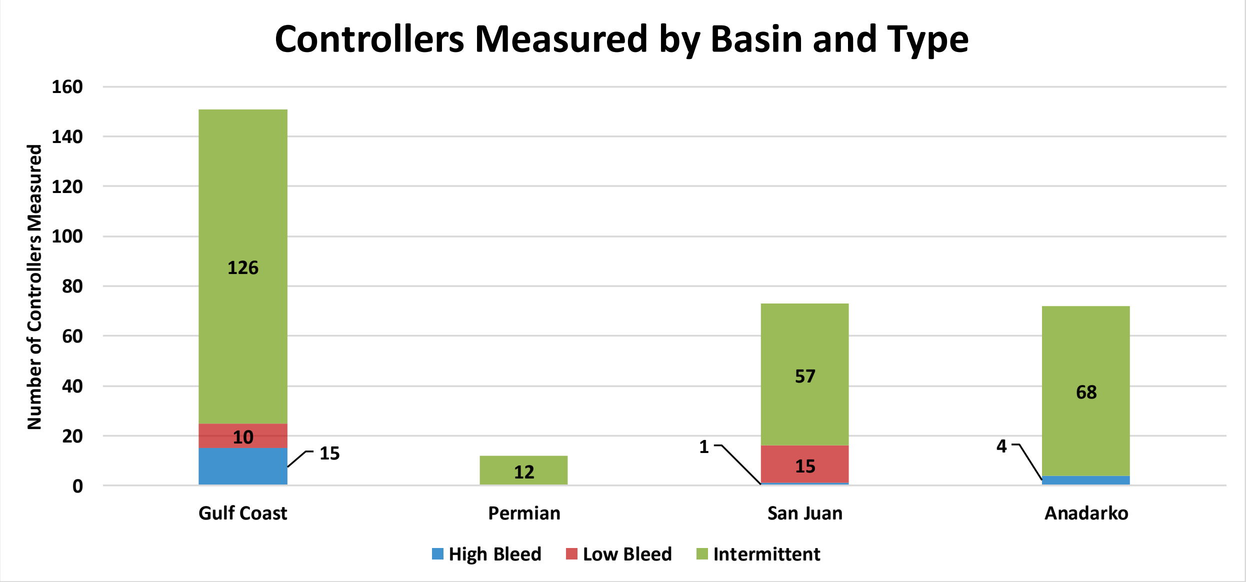


Figure 3: Number of pneumatic controllers measured by EPA type and basin.

Previous studies have reported pneumatic controller emission results on an average emission rate per controller basis. For this study, average emission rates by basin and controller type are shown relative to US EPA Subpart W emission factors (Figure 4, Table 2), however they should be interpreted with caution. Basin-level average emission rates for both continuous vent, high and low bleed types are limited by small sample sizes. Although the sample size of the intermittent vent pneumatic controller measurements is larger, intermittent vent controllers are analyzed by the subcategories of properly functioning and malfunctioning which reduces the sample size in each subcategory.

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[3] Three of the controllers measured and classified as intermittent vent controllers are listed as displacement tanks for wastewater/oil by the manufacturer and differ from the typical understanding of intermittent vent controllers. However, they were retained in the study reports and statistics.

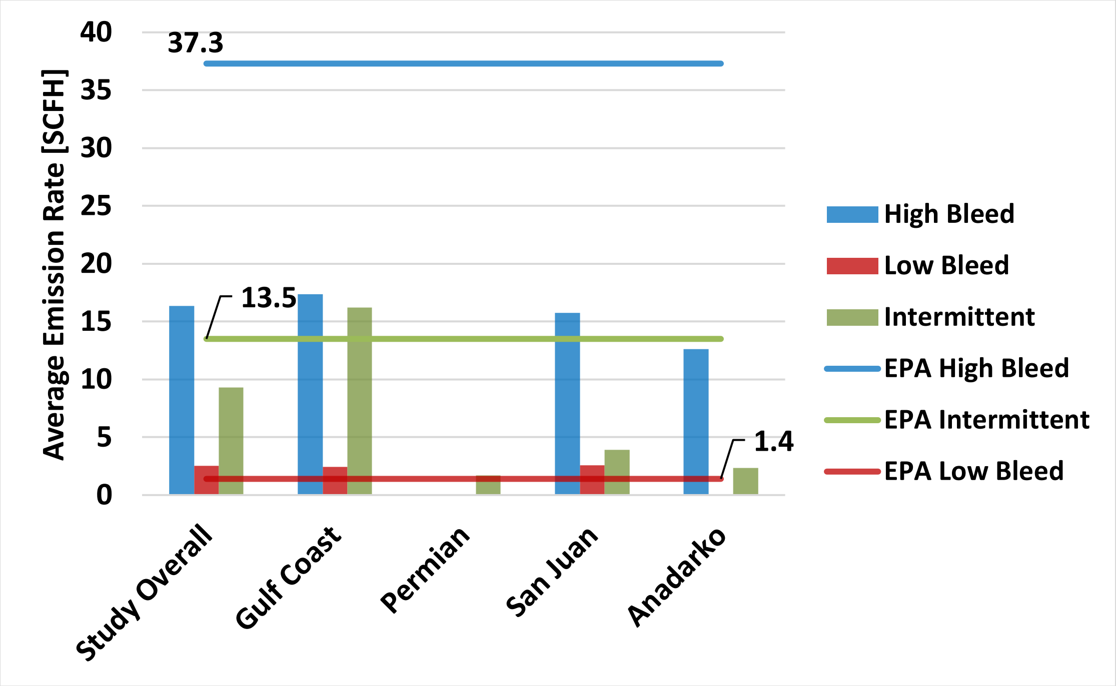


Figure 4: Average emission rates per controller by type and basin compared to US EPA Subpart W emission factors.

Table 2: Average emission rates per controller by type and basin in SCFH.
ND indicates that no measurements were made for the type of controller within the basin.

	Study Overall	Gulf Coast	Permian	San Juan	Anadarko
All Controllers	9.2	15.4	1.7	3.7	2.9
High Bleed	16.4	17.4	ND	15.7	12.6
Low Bleed	2.6	2.7	ND	2.6	ND
Intermittent	9.3	16.2	1.7	3.8	2.3

The intermittent vent pneumatic controller average emission rate for all measured intermittent vent pneumatic controllers represents the average emission rates of properly functioning and malfunctioning controllers. Actions taken to minimize the number of malfunctioning pneumatic controllers, such as a proactive monitoring and repair program, may result in a reduction in the number of malfunctioning intermittent controllers and thus reduce emissions. Emission factors were derived by the properly functioning and malfunctioning sub-categories, akin to leak/no-leak factors applied to fugitive components (US EPA, 1995). For the overall study, malfunctioning intermittent pneumatic controllers (~38% malfunction rate in this data set) contributed about 98% of the observed intermittent pneumatic controller emissions.

Intermittent Vent Pneumatic Controller Emissions Analysis

In this study, 263 intermittent vent pneumatic controllers were measured. The 120 resultant time series with no instantaneous measurements greater than 0.39 SCFH (1.5 times the effective resolution, the assumed actuation threshold) were considered minimally emitting. Emissions with data above the actuation threshold were observed in the remaining 143 time series. Any individual instantaneous measurement in the time series below 0.13 SCFH (1/2 the effective resolution of 0.26 SCFH) was replaced with a value of 0.13 SCFH.

Based on the observed time series, pneumatic controllers were classified as either properly functioning or malfunctioning. Minimally emitting time series were a subset of properly functioning time series where no actuations were observed. Properly functioning intermittent pneumatic controller time series were those characterized by either distinct, episodic actuations, with a clear return to a baseline of 0.13 SCFH in between actuations, or with consistently *de minimis* emission rate (< 0.39 SCFH – actuation threshold of 1.5 times the effective resolution). Time series from malfunctioning intermittent pneumatic controllers typically showed continuous emissions with no return to baseline. Examples of a properly functioning intermittent pneumatic controller (top panel) and a malfunctioning intermittent pneumatic controller (bottom panel) are show in Figure 5.

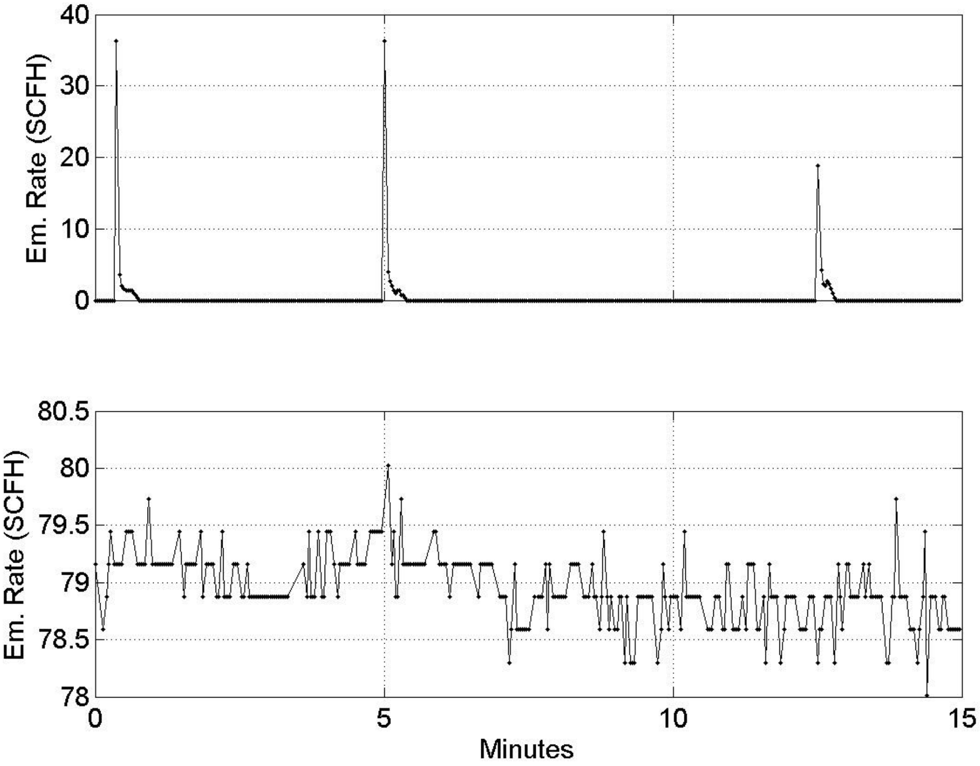


Figure 5: Top panel: Properly functioning intermittent vent pneumatic controller (the baseline level is 0.13 SCFH). Bottom panel: Malfunctioning intermittent vent pneumatic controller.

The following algorithm was developed to provide a consistent basis for classification as described below.

Intermittent vent controllers were classified as properly functioning where:

1. The median emission rate was less than 0.39 SCFH
2. Greater than 25% of a time series had an emission rate less than 0.39 SCFH
3. All individual actuations lasted less than 180 seconds (~20% of the measurement duration)

Otherwise, the pneumatic controller was classified as malfunctioning.

The third criterion above is based on the expectation that actuations should occur over a limited duration with a return to a low level value. The 3 time series that failed this criteria had unexpectedly prolonged actuations indicative of a malfunctioning intermittent controller (*i.e.*, such as the bottom panel in Figure 5). Automated classifications were visually confirmed based upon engineering judgment.

The automated algorithm for determining if an intermittent pneumatic controller is properly functioning or malfunctioning used here is specific to this dataset because it is based on the minimum effective resolution of the dataset. The algorithm can potentially be adapted for use on other datasets based on their minimum effective resolution, but this should be verified prior to its implementation.

Average emission rates for each of the intermittent vent controllers were calculated (Table 3). Of the 263 total time series analyzed, 120 were minimally emitting. Of the 120 minimally emitting intermittent controllers, 11 had an average emission rate greater than 0.13 SCFH but less than 0.39 SCFH with a mean value of 0.21 SCFH, giving an average overall emission rate of 0.137 SCFH for all 120 minimally emitting intermittent pneumatic controllers. An additional 44 were classified as properly functioning with a mean emission rate of 0.66 SCFH for a total of 164 properly functioning intermittent pneumatic controllers with a mean emission rate of 0.28 SCFH. An additional 99 intermittent pneumatic controllers were malfunctioning with a mean emission rate of 24.1 SCFH. The average emissions per controller for all 263 intermittent vent controllers was 9.25 SCFH.

Table 3: Average emission rates per intermittent controller by type in SCFH.

	Average Emission Rate (SCFH)
Properly Functioning	0.28
Malfunctioning	24.1
All Intermittent	9.25

Actuation Frequency Sensitivity Analysis

Pneumatic controllers that were observed as minimally emitting during the study were expected to actuate on some frequency despite not having been observed over the course of this study. A sensitivity case was evaluated to assess the maximum potential error in the average emission rate based upon a conservative scenario assuming the measurement team had just missed an actuation. The sensitivity case assumed each of the minimally emitting pneumatic controllers actuated every 20-minutes with an actuation volume equal to the average emission volume per actuation of the properly functioning, but not minimally emitting, pneumatic controllers (0.02 SCF per actuation). The average emissions per controller for all 263 intermittent pneumatic controllers increased by ~0.1 % from 9.25 SCFH to 9.26 SCFH under this scenario. Thus, unaccounted for actuations of properly functioning controllers, even at a very high actuation rate, had a minimal effect on the total emissions which is consistent with sensitivity analyses in Allen et al. (2015).

Intermittent Pneumatic Controller Population Distributions

Cumulative distribution functions (CDFs) were fitted to the data to facilitate visualization of the relative populations (properly functioning vs. malfunctioning across regions). Weibull CDFs were fitted to the average emission rate data. Figure 6 shows the CDFs fitted to emission rates for the malfunctioning and properly functioning intermittent pneumatic controllers, respectively. Minimally emitting controllers were omitted from the fitting procedure because fitting a continuous distribution to data that contains a large number of non-unique data points leads to poor distribution fits. Those data were added back into the probability distribution plots (Figures 7 and 8).

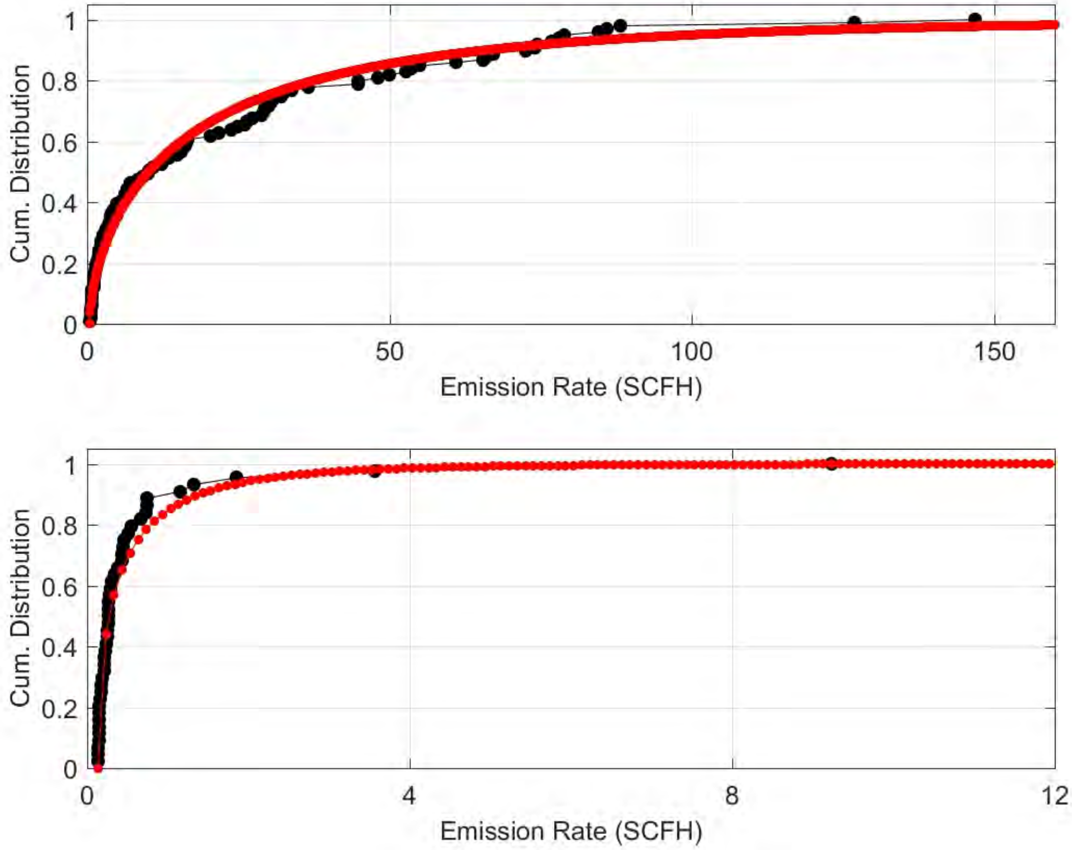


Figure 6: Top panel: Malfunctioning intermittent pneumatic controller emission rates (black circles) with fitted CDF (red line). Bottom panel: Properly functioning intermittent pneumatic controller emission rates (black circles) with fitted CDF (red line) excluding minimally emitting data.

Table 4: Parameters of the Weibull CDF distributions fitted to the malfunctioning and properly functioning data (excluding minimally emitting).

	Weibull scale parameter	**Weibull shape parameter**
Properly functioning	0.2735	0.5463
Malfunctioning	17.4266	0.6294

The relative contribution of emissions as a function of emission rate for properly functioning and malfunctioning intermittent vent pneumatic controllers, including minimally emitting pneumatic controllers, is shown in Figure 7. The malfunctioning intermittent controllers account for about 98% of the measured emissions from intermittent vent controllers. The primary driver of emissions in this dataset are the highest emissions from malfunctioning intermittent vent pneumatic controllers. The top 15 pneumatic controller emission rates (15 of the 263 or ~5.7 %), which were malfunctioning and emitting at a rate of at least 60 SCFH, account for about 51% of the emissions from all 263 intermittent pneumatic controllers.

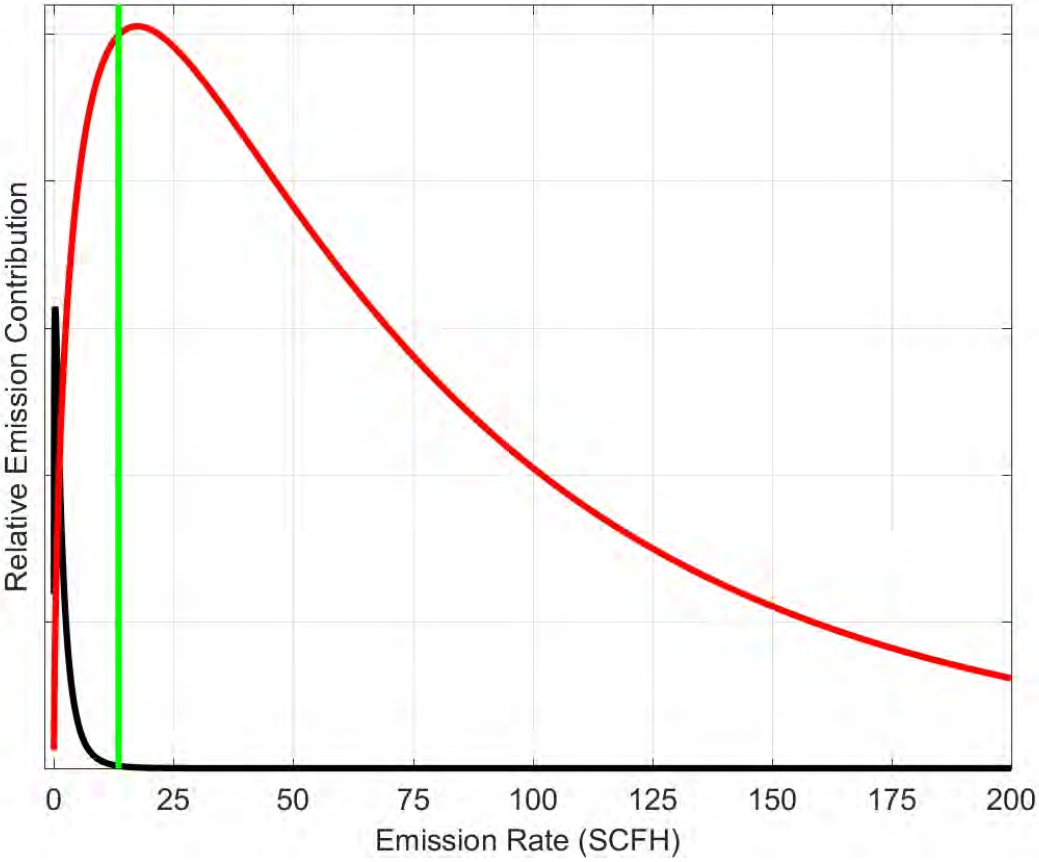
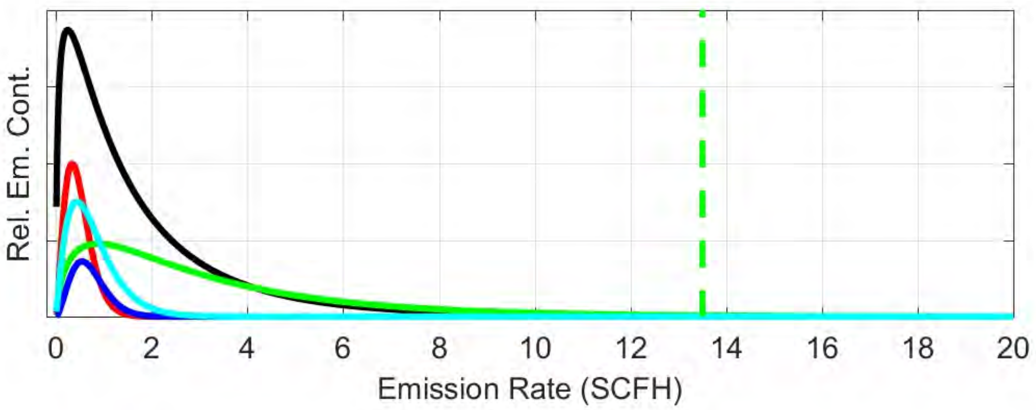


Figure 7: Relative contribution of properly functioning intermittent pneumatic controllers including minimal emitting controllers (black line), malfunctioning intermittent pneumatic controllers (red line), and the Subpart W intermittent vent pneumatic controller emission factor (green line).

A similar analysis was performed on the subsets of data for each of the four basins included in this study. The relative contributions of emissions for each region as a function of emission rate for properly functioning and malfunctioning pneumatic controllers, including minimally emitting pneumatic controllers, are shown in Figure 8, while Table 5 provides the Weibull scale and shape parameters for the fits. Note that there was only one malfunctioning pneumatic controller in the Permian basin so a fit was not possible.



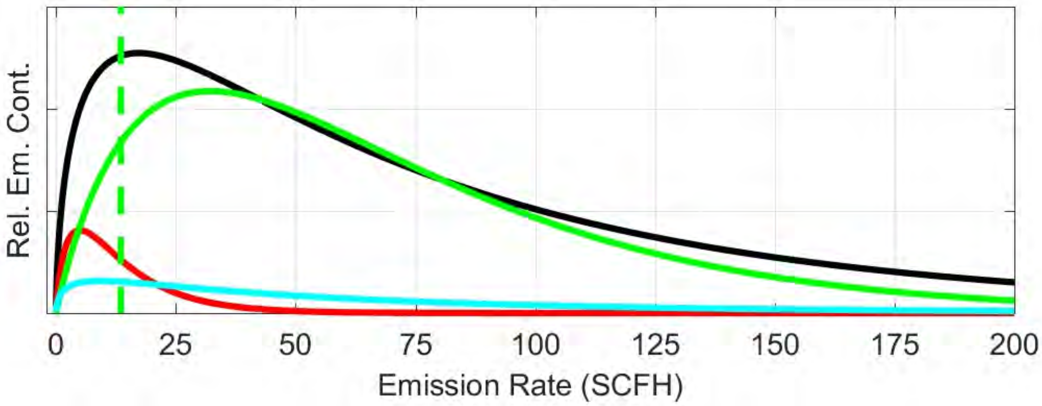


Figure 8: Top panel: Relative contribution of emissions for properly functioning intermittent pneumatic controllers, including minimally emitting controllers, by basin. Bottom panel: Relative contribution of emissions for malfunctioning intermittent pneumatic controllers by basin.

For both panels: The black line represents all the data (Figure 8). The red line represents the Anadarko basin, the green line represents the Gulf Coast basin, the blue line represents the San Juan basin. The green dashed line represents the Subpart W intermittent vent pneumatic controller emission factor.

Table 5: Weibull distribution parameters for properly and malfunctioning pneumatic controllers for the four basins.

Basin	Weibull scale parameter	Weibull shape parameter
Properly Functioning		
Anadarko	0.3377	1.3425
Gulf Coast	0.8784	0.7180
Permian	0.5451	1.5642
San Juan	0.4349	1.0913
Malfunctioning		
Anadarko	5.0269	0.8210
Gulf Coast	32.9045	0.9568
Permian	---	---
San Juan	9.1526	0.5492

Emission Factor Development

The Gulf Coast basin contributed the largest number of emitters and volume of emissions to the malfunctioning intermittent controller category as well as total emissions in this study. The Gulf Coast basin had 13 of the 14 top emitting intermittent pneumatic controllers. The remaining top emitting malfunctioning intermittent pneumatic was located in the San Juan basin. Excluding the single top emitter for the San Juan basin drops the mean emission rate value per malfunctioning intermittent controller for the San Juan basin from 17.4 SCFH to 7.5 SCFH and also significantly alters the Weibull scale parameter in the CDF fit for malfunctioning intermittent pneumatic controllers in the San Juan basin from 9.1526 to 5.6217. This illustrates the sensitivity of the pneumatic controller emission rate to the distribution of properly functioning and malfunctioning intermittent pneumatic controllers.

The skewed distribution of emissions, where a small number of malfunctioning intermittent pneumatic controllers accounted for the majority of measured emissions, suggests that a malfunctioning pneumatic controller monitoring and repair program may be effective in reducing emissions far below the current emissions estimates. Many operators report that they voluntarily practice such an inspection program in locations where the company is already performing leak detection and repair inspections. Unfortunately, there is no opportunity to demonstrate the reductions that such a program achieves because Subpart W requires the application of a single factor in the tabulation of intermittent vent pneumatic controller emissions irrespective of whether the controller is functioning properly or malfunctioning.

Table 6 shows the detectable portion of this study's measured emissions under different detection threshold scenarios. Malfunctioning intermittent vent pneumatic controllers emitting at a rate > 2 SCFH (an emission rate likely detectable with an optical gas imaging camera) account for about 97.6 % of the total emissions based upon the intermittent vent pneumatic controllers measured in this study. For a threshold of 10 SCFH, which may be detectible by audio-visual-olfactory (AVO) monitoring, about 92.3% of the emissions could potentially be located and significantly reduced.

Table 6: Specified detection threshold, the number and percentage of malfunctioning intermittent pneumatic controllers emitting above that threshold, as well as the percentage of total intermittent vent controller emissions represented by malfunctioning controllers emitting above the specified threshold.

Detection Threshold (SCFH)	# of Intermittent pneumatic controllers	% of Intermittent pneumatic controllers	Detectable % of Total Intermittent Controller Emissions
2	78	29.6	97.65
4	66	24.6	96.04
6	61	22.7	95.05
10	51	19.3	92.30
25	35	13.3	81.78
50	19	7.2	59.97
75	8	3.0	31.51
100	2	0.8	11.25

A stratified emission factor approach (e.g. Table 3) could be applied to intermittent pneumatic controllers to account for properly functioning and malfunctioning controllers. The approach is analogous in design to application of leaker emission factors for equipment leaks in Subpart W when an OGI leak inspection program is in place. Such an approach would enable demonstration of reductions by operators who are voluntarily conducting pneumatic controller inspections and potentially incentivize further voluntary inspections to identify malfunctioning pneumatic controllers.

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ANNEX B: API Comments on Proposed Subpart W, Submitted July 21, 2023

July 21, 2023

<u>Submitted electronically to docket No. EPA-HQ-OAR-2019-0424</u>

Jennifer Bohman
Climate Change Division, Office of Atmospheric Programs (MC-6207A)
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Docket No. EPA-HQ-OAR-2019-0424

Dear Ms. Bohman:

The American Petroleum Institute, the American Exploration & Production Council, Independent Petroleum Association of America, The Petroleum Alliance of Oklahoma, and the Offshore Operators Committee (collectively "Industry Trades") appreciate the opportunity to offer comments to the U.S. Environmental Protection Agency (EPA) on the proposed “Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule” (proposed on May 22, 2023). With this submittal, the Industry Trades seek to continue our participation in the rulemaking process as a collaborative stakeholder by providing meaningful solutions to address EPA’s goals while addressing the burden of data collection (and identifying potential unintended consequences) that could result if the rulemaking is finalized as proposed.

We have participated as key collaborative stakeholders throughout the process of developing the EPA Greenhouse Gas Reporting Program (GHGRP) by contributing expertise and proposing solutions that address EPA's policy goals while reflecting the reality of the industry and its evolving day-to-day operating practices. The Industry Trades have directed our efforts toward seeking a balance between the burden of data collection and reporting, the need to protect sensitive information and ensure that reporting requirements are placed on the correct reporters, and the need for providing the highest quality data that will help inform decision makers and the public.

These comments reflect our continued interest in the evolution of the GHGRP to provide an accurate accounting of greenhouse gas (GHG) emissions from facilities across the full value chain of the oil and natural gas industry. Our comments cover concerns and recommendations in the wide range of sectors that relate to the operations of our collective members.

INDUSTRY TRADES' INTERESTS

The American Petroleum Institute (API) is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader convening subject matter experts from across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 800 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Additionally, API has a history of working with EPA to refine and improve data collection, emission estimation and emission reporting under various subparts of the GHGRP. API has worked with both EPA and the regulated industry for more than two decades in developing methodologies for estimating greenhouse gas emissions from oil and natural gas operations. API's first *Compendium of GHG Emissions Methodologies for the Oil and Natural Gas Industry* (the *Compendium*) was published in 2001. As reflected in EPA's efforts to revise the GHGRP and API's recent publication of a 4th edition of the *Compendium (November 2021)*, our abilities to estimate and measure greenhouse gas emissions are continually evolving.

The American Exploration & Production Council (AXPC) is a national trade association representing 30 of the largest independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of ensuring positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

The Independent Petroleum Association of America (IPAA) represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The Petroleum Alliance of Oklahoma (The Alliance) represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. The Alliance's members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas and play an essential role in providing products and solutions to improve human health and welfare, power the global economy, and make modern life possible. Abundant, clean-burning natural gas has enabled the United States to become the global leader in greenhouse gas emissions reductions. The Alliance's members have and will continue to deploy technologies that result in meaningful greenhouse gas emission reductions through innovative solutions and breakthrough technologies while meeting the energy demands of today and the future.

The Offshore Operators Committee (OOC) is an offshore energy trade association that serves as a technical advocate for over 90% of the companies operating on the U.S. Outer-Continental Shelf (OCS). Founded in 1948, the OOC has evolved into the principal technical representative regarding regulation of offshore energy operations. Our members include operators and service providers working to ensure safe production of offshore energy for the workforce and the environment.

Industry Trades' Comments on EPA's "Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule"

Docket ID No. *EPA-HQ-OAR-2019-0424*

1. Introduction

The Industry Trades support efforts to improve accuracy and enhance consistency between regulatory programs as it relates to greenhouse gas (GHG) reporting. The comments provided herein reflect feedback from the Industry Trades on the proposed changes to the GHGRP for subparts impacting the oil and natural gas industry, with a particular focus on the newly proposed Subpart B's burdensome reporting and recordkeeping requirements as well as potential unintended consequences resulting from these requirements. The Industry Trades are respectfully submitting comments on the following subparts:

- Subpart A – General Provisions
- Subpart B – Energy Consumption
- Subpart C – General Stationary Fuel Combustion
- Subpart P – Hydrogen Production
- Subpart Y – Petroleum Refineries
- Subpart PP – Suppliers of Carbon Dioxide
- Subpart UU – Injection of Carbon Dioxide
- Subpart WW – Coke Calciners

As presented in Sections 2 and 3 below, the Industry Trades' comments are organized by proposed amendments to current subparts and proposed new subparts, respectively.

2. Comments on Proposed Amendments to 40 CFR Part 98

1. Subpart A – General Provisions

a. The Industry Trades support EPA's proposal to update the Global Warming Potentials (GWPs) for calculating CO_2-equivalent (CO2e) emissions of non-CO_2 gases (CH_4, N_2O, HFCs, PFCs, SF_6, and NF_3) to reflect updated estimates contained in the Intergovernmental Panel on Climate Change's (IPCC's) Fifth Assessment Report (AR5), based on a 100-year time horizon. We agree with EPA's proposal to use the 100-year GWP for methane. The proposed GWP changes to Table A-1 in Subpart A are aligned with the Inventory of U.S. Greenhouse Gas Emissions and Sinks [i.e., the U.S. EPA GHG Inventory (GHGI)] and complies with the United Nations Framework Convention on Climate Change (UNFCCC) decision to use GWP values from the IPCC AR5 in national reporting by countries by the end of 2024.

While the Industry Trades agree with the proposed revisions to the GWPs included in Subpart A, the Industry Trades request that EPA clarify in the preamble to this proposed rulemaking the impacts on the reported total CO_2e emissions due to changing the GWP (particularly for methane), without any actual change in mass emissions. With an increased focus on methane emissions from the oil and natural gas industry, it is important to inform stakeholders that future increases in CO_2e emissions due to the change in GWP are not reflective of any actual mass emission increases. Likewise, the Industry Trades recommend that the EPA acknowledge that combustion CO_2e emissions will be impacted from both the reduction in N_2O GWP, as well as the increase in CH_4 GWP.

2. Subpart C – General Stationary Fuel Combustion

The EPA's proposed revisions include requirements to report emissions from the stationary combustion category that result from an electricity generating unit (EGU) and to report an estimated fraction of total emissions from a multi-unit group of combustion sources under 40 CFR 98.36(c) attributable to EGUs. The preamble to the supplemental proposed rule states that "some manufacturing facilities, such as petroleum refineries and pulp and paper manufacturers, operate stationary combustion sources that generate electricity. Reporting of an EGU indicator for these units would allow the EPA to assign the emissions from any electricity generating units at the facility more appropriately to the power plant sector."[1]

a. An EGU is not specifically defined within Subpart A or Subpart C; the definition of an "electricity generation source category" EGU found in Subpart D in 98.40 includes only EGUs that are subject to monitoring and reporting requirements found in 40 CFR Part 75. While EGUs are not defined in Subpart A explicitly, a footnote to Table A-7, "Data Elements that Are Inputs to Emission Equations and for Which the Reporting Deadline is March 31, 2015" states that for sources reporting under Subpart C (cited below with **emphasis added**). The Industry Trades are seeking clarification on the definition of an EGU for this reporting element; as proposed, it is unclear what units would meet this reporting requirement. The Industry Trades support a definition that aligns with the footnote presented under Table A-7:

   Required to be reported only by: (1) Stationary fuel combustion sources (e.g., individual units, aggregations of units, common pipes, or common stacks) subject to subpart C of this part that contain at least one combustion unit ***connected to a fuel-fired electric generator owned or operated by an entity that is subject to regulation of customer billing rates by the PUC (excluding generators connected to combustion units subject to 40 CFR part 98, subpart D) and that are located at a facility for which the sum of the nameplate capacities for all such electric generators is greater than or equal to 1 megawatt electric output;*** *and (2) stationary fuel combustion sources (e.g., individual units, aggregations of units, common pipes, or common stacks) subject to subpart C of this part that do not meet the criteria in (1) of this footnote that elect to report these data elements, as provided in § 98.36(a), for reporting year 2014.*

   Additionally, the Industry Trades propose that the definition of an EGU specifically exclude drivers used to power equipment including but not limited to compressors and pumps.

b. The Industry Trades also propose that the EPA provide clarification and flexibility to 98.34(e), which references 98.34(d) to determine the biogenic portion of CO_2 emissions. Since gaseous fuels can be sampled prior to combustion for biogenic content and used to determine the biogenic portion of CO_2 emissions, the Industry Trades propose the following additional language (***in red***) to provide options to use other approved sampling standards or industry standard practices:

   "(e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, *e.g.,* tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866-16 and ASTM D7459-08 (both incorporated by reference, see §98.7) may be used to determine the biogenic portion of the CO_2 emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. ***As an alternative to ASTM D7459-08 and paragraph (d), an entity may also use a method published by a consensus-based standards organization, if such a method exists, or you***

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[1] 88 Fed. Reg. at 32873.

may use industry standard practice. The method(s) used shall be documented in the GHG Monitoring Plan required under 98.3(g)(5). If the primary fuel for multiple units at the facility consists of tires, and the units are fed from a common fuel source, testing at only one of the units is sufficient."

c. In the proposed revisions to Subpart C, EPA should move all combustion calculations and reporting requirements from Subpart W to Subpart C in order to avoid confusion in reporting natural gas combustion emissions, as previously articulated in the Industry Trades' comments submitted on October 6, 2022.[2]

d. Additionally, site-specific CH_4 emission factors may be available for certain equipment from the equipment manufacturer or from acceptable testing methodologies. EPA should allow for the use of site-specific CH_4 emission factors as an alternative to the CH_4 emission factors in Tables C-2 or Table W-9, with the following proposed addition (below, ***in red***) to 98.33(c)(1) through 98.33(c)(4). Required use of generic factors disincentivizes reporters to mitigate and reduce methane emissions. This change would also be consistent with the recently proposed updates to 40 CFR Part 98, Subpart W.

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH4 emission factor from Table W–9 to subpart W of this part, ***Table C-2, or site-specific emission factors****.*

3. Subpart P – Hydrogen Production

In general, this subpart proposes to include all facilities that produce a hydrogen product(s) including non-merchant hydrogen production process units previously reported under Subpart Y (Petroleum Refineries) and captive plants, but excludes reporting of catalytic reforming units. EPA also proposes that the associated steam consumption for these units and their fuel usage previously reported under Subpart C (Combustion) be reported under Subpart P.

a. The Industry Trades support the exemption to the source category in 40 CFR 98.160(b)(1)(B) clearly excluding catalytic reforming units covered under Subpart Y from reporting in Subpart P.

b. The Industry Trades do not support amending the source category requiring reporters to report combustion from hydrogen production process units under Subpart P in lieu of Subpart C as proposed in 40 CFR 98.160(c). These units may not be metered separately from other combustion units located at an integrated facility such as a refinery with a hydrogen production unit; therefore, we recommend reporting stationary combustion emissions from hydrogen production under Subpart C. If those emissions have to be reported under Subpart P instead of Subpart C, EPA shall allow engineering estimation for fuel consumption to avoid burdensome retrofitting of fuel meters.

c. The Industry Trades are also concerned that reporting the net quantity of steam consumed as proposed under 40 CFR 98.166(b)(9) could result in duplicative reporting based on what is proposed to be reported under Subpart B (i.e., where steam is provided by a third-party supplier). The Industry Trades respectfully request removal of this requirement from Subpart P.

d. EPA is seeking comment as to how to determine when or how a source will trigger or cease to report under Subpart P. EPA is proposing to use hydrogen production rates as the trigger for GHG reporting, instead of direct GHG emissions. EPA believes this approach will capture hydrogen production units which use energy (rather than

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[2] API comments to EPA's proposed GHGRP Rule, October 6, 2022.

fossil fuel combustion). The Industry Trades believe that these types of units will frequently be part of a larger operation already subject to GHG reporting, and energy consumption will be captured under Subpart B.

The Industry Trades offer the following recommendations on the provisions to cease reporting:

i) Hydrogen production process units which produce hydrogen but emit no direct GHG emissions should become eligible to cease reporting starting January 1 of the following year after the cessation of direct GHG emitting activities associated with the process;

ii) If the direct GHG emissions remain below 15,000 MT CO2e or between 15,000 and 25,000 MT CO2e, the Industry Trades recommend that reporting would be required for 3 or 5 years respectively, aligned with the existing Part 98 reporting off-ramp provisions; or

iii) If EPA establishes a hydrogen production threshold for reporting, then the Industry Trades recommend that falling below that production threshold should be the trigger for cessation of reporting, either starting January 1 of the following year or on a parallel structure to the 3- and 5-year off-ramp emission thresholds.

The Industry Trades recommend that if the hydrogen production unit continues to combust fuel or is part of a larger process with multiple (or comingled) combustion units, those emissions will continue to be reported under Subpart C, consistent with the Industry Trades' recommendation above. Similarly, if the process unit is part of a refinery, any non-combustion energy consumption related to the process unit will be captured under proposed Subpart B.

e. EPA is seeking input on requiring sales information for hydrogen production. There are several reasons the Industry Trades believe this should not be required unless proposed through a separate rulemaking process.

i. First, it is important to note that the hydrogen market is in its very early stages, and it is unknown how hydrogen for energy consumption may evolve in the near or longer term. Codifying this in the regulation will require a full regulatory rulemaking process to address changing market conditions. As this market is evolving, it is possible this proposed new GHGRP requirement will become overly burdensome without providing useful information.

ii. Second, this information is considered "Confidential Business Information" (CBI) by both the seller and/or the buyer and may be restricted by confidentiality provisions in sales contracts; therefore, it should not be publicly reported.

iii. Finally, it is not clear how this information would be used by EPA; information necessary to determine emissions intensity is already provided in Subpart P.

If EPA disagrees with the recommendations above, the Industry Trades recommend limiting the reporting requirement to include only bulk hydrogen sales quantities, without specifying individual buyers identities and sales quantities. If reporting sales information is required, the Industry Trades recommend reporting at corporate level, rather than individual transactions, and that a cut-off threshold for reporting be established, similar to Subpart NN.

4. Subpart Y – Petroleum Refineries

Proposed revisions to Subpart Y include deletion of the reference to non-merchant hydrogen production plants and to coke calcining units as these are being addressed in Subparts P and WW, respectively. Additionally, EPA is proposing to include a requirement to report the capacity of each asphalt blowing unit.

The Industry Trades support the removal of reporting requirements for non-merchant hydrogen production plants in Subpart Y, and instead report these units under Subpart P. Likewise, the Industry Trades support the reporting of coke calcining units in the newly added Subpart WW.

EPA's rationale for requesting the capacity of each asphalt blowing unit is not clear to the Industry Trades, nor is it clear how this data would be used. t is unclear how the individual capacity data will support more accurate reporting. With the additional data collection and reporting requirements, the Industry Trades would like to better understand EPA's reasoning for requesting this information, so that we can recommend the most appropriate and effective data to meet EPA's objectives.

5. Subpart PP – Suppliers of Carbon Dioxide

As proposed, reporters would be required to report the facility identification number associated with the annual GHG reports for each Subpart RR and VV facility to which CO_2 is provided. Additionally, EPA is seeking comment on whether to expand the reporting requirements for all receivers of CO_2, not just those facilities subject to Subparts RR and VV.

a. The Industry Trades support EPA's efforts to increase accuracy in tracking supplies of CO_2 in the economy, but request EPA to analyze whether both senders and receivers of CO_2 reporting is redundant.

b. The Industry Trades also recommend that EPA provides additional information on how CO_2 suppliers for export could appropriately address exports in their report. For example, clarity in reporting is needed to address situations in which a company supplies CO_2 to a non-reporter that is a subsidiary of a larger company that does report.

c. EPA is seeking comment on further expanding the list of end-use applications reported in 40 CFR 98.426(f) to better account for and track emerging CO_2 end uses. Similar to our comments under Subpart P, the market for CO_2 utilization continues to develop. As such, the Industry Trades are recommending EPA allow, in this rulemaking, flexibility in how this information is reported by allowing reporters the ability to select from a representative range of end-uses, including allowing for instances when the end-use is 'other'. The Industry Trades believe that this information could be captured in EPA's forms and updated as needed to account for innovation in this emerging market.

6. Subpart UU – Injection of Carbon Dioxide

The Industry Trades support EPA's efforts to increase clarity and reduce the potential for double counting of reported emissions. In addition, the Industry Trades support EPA's proposal to revise the proposed text in 40 CFR 98.470(c) from "are not required to report" to "shall not report."

3. Comments on Proposed New Source Categories to Part 98

1. Subpart B – Energy Consumption

This newly proposed subpart will require those reporters that are already subject to reporting under existing provisions in 40 CFR Part 98 to:

- Report the quantity of purchased electricity and thermal energy products;
- Develop a Metered Energy Monitoring Plan (MEMP), which includes identifiers for each meter (including photographs), accuracy specifications, manufacturer's certifications, and other details;
- Keep documentation of quality assurance for purchased electricity monitoring including documentation that meters are conforming with appropriate ANSI standards;
- Keep documentation of quality assurance for purchased thermal energy including copies of the most recent audit of the accuracy of each meter in the purchasing agreement, and if the audit is more than 5 years old, documentation of a request for a new audit to the energy provider (and auditing the meter every 5 years); and
- Report multiple pieces of information for every bill for every purchased energy product meter, as well as requiring submittal of representative billing statements for each purchasing agreement.

The Industry Trades believe many of the provisions within the proposed regulation are extremely burdensome for geographically disparate operations such as those found in the oil and natural gas industry and focus our comments on the unique challenges associated with the meter-level recordkeeping and segment level reporting. In general, the Industry Trades believe there are ways to provide energy consumption information to EPA in a way that achieves EPA's policy goal while not imposing overly burdensome requirements to energy purchasers. Specifically, the Industry Trades recommend EPA to:

- Allow energy purchasers subject to reporting under Subpart W to report energy consumption for all Subpart W activities within a single AAPG hydrocarbon basin;
- Generally, remove meter-level recordkeeping and reporting requirements for the purchaser of energy. If required, any such meter-level requirements should be provided by the electricity supplier as the owner/operator of the meters;
- Remove meter-level QA/QC requirements from the energy purchaser, and instead require energy providers to ensure meters meet required accuracy requirements as the owners of the equipment;
- Exempt Subpart B reports from the "Substantive Error" provisions found in Subpart A; and
- Remove the requirement for a separate MEMP plan, but instead allow reporters to augment existing GHG recordkeeping procedures in the Greenhouse Gas Monitoring Plan (as required in 40 CFR 98.3(g)(5), with additional requirements in subsequent subparts), to include backup documentation, procedures, QA/QC methodologies and other supporting data. This information would be available upon request by EPA.

The following commentary is provided as context to these recommendations.

The proposed recordkeeping, QA/QC and reporting requirements as proposed in this supplemental rulemaking are extremely burdensome for oil and natural gas operations and could result in disincentivizing site electrification. For the oil and natural gas operations that cover a large geographical area consisting of numerous assets, such as onshore oil and gas production and onshore gathering and boosting where the facility encompasses assets across an entire American Association of Petroleum Geologists (AAPG) basin, the number of energy providers and the number of individual meters can be quite significant. For example, in the Permian Basin, a medium-sized upstream operator could have more than 5,000 individual well sites and tank batteries across more than 70,000 square miles and could have hundreds if not thousands of energy meters. Some operations in Alaska and North Dakota have very limited timeframes during which weather would allow for the proposed meter-specific data collection efforts (e.g., meter photos, meter numbers, etc.). Providing documentation on a meter-by-meter basis, including billing statements, would result in an extremely burdensome reporting process, requiring uploading billing statements for hundreds, if not thousands, of meters for individual reporting entities. This is an excessive reporting requirement given that it is likely that the vast majority of meters used in the upstream oil and natural gas segment are for very small energy consuming sites, are not owned or operated by the energy purchaser, and do not serve a specific purpose beyond the reported values. Additionally, imposing these extremely burdensome recordkeeping, reporting and QA/QC requirements for energy purchasers could ultimately result in disincentivizing site electrification, which would be in contrast to the current Administration's drive toward electrification.

Separating energy consumption between reporting segments (e.g., onshore production versus gathering and boosting or gas processing) will be particularly challenging for large integrated operations. The Industry Trades recommend allowing operators subject to Subpart W reporting to report all energy consumption for all reportable Subpart W operations within a single AAPG hydrocarbon basin. Many oil and natural gas operators in the U.S. report both onshore production and gathering and boosting within the same basin and across multiple basins. The proposed data requirements under Subpart B would represent a significant and burdensome data collection effort to not only collect the meter-level data for these multi-asset facilities, but to also then separate the data between the onshore production, gathering/boosting and other GHG reporting segments. In many instances, it is not as simple as a single meter serving a single facility or reporting segment - there are meters recording data across the entire value chain with overlap between the segments - this further complicates a reporters' ability to divide that energy consumption between reporting segments. The Industry Trades request that EPA allow operators who are subject to reporting under Subpart W to report ALL consolidated energy consumption from Subpart W operations within the AAPG basin. If required to report energy by Subpart W source category (i.e., by segment), the Industry Trades request EPA to allow estimation of energy usage between Subpart W facilities, to account for the need to allocate between different facility types (e.g., onshore production, gathering and boosting, etc.) where meters cover energy use across the value chain.

Meter level identification, auditing, accuracy and QA/QC requirements should not be incumbent upon the energy purchaser; instead, these requirements should apply to the meter owner, which is the energy provider. The Industry Trades are concerned that the monitoring and QA/QC requirements proposed in 40 CFR § 98.24, and the reporting requirements in 40 CFR §98.26, will be particularly burdensome given that many of the proposed accuracy and QA/QC requirements would be the responsibility of the energy purchaser rather than the energy provider, despite the fact the energy purchaser does not own, maintain or control the meters. Placing the responsibility for the proposed data requirements on the energy purchaser is inappropriate because it is the energy providers (such as electric utilities) that own and operate the energy meters and are responsible for their accuracy. Further, it is not uncommon for energy providers to change or replace meters without informing the electricity purchaser; therefore, reporting any meter-specific data supplied by an energy purchaser could become inaccurate without the knowledge of the purchaser. Similarly, the energy purchaser does not have access to documentation that the meters conform to ANSI standards, and likely does not have the ability to request that information from the energy provider.

As proposed, the recordkeeping and reporting requirements in Subpart B require reporting detailed supplemental data not required by any other subpart in the GHGRP, and therefore should not be required here. Reporters are not required to submit this level of documentation for other subparts, but instead follow the recordkeeping requirements codified in 40 CFR and the appropriate subparts. The Industry Trades support that same approach for Subpart B. If EPA requires meter-level reporting, the Industry Trades suggest the requirement for supplying energy meter data should reside with the energy provider, not the purchaser.

The Industry Trades provide additional comments on the following specific aspects of the supplemental proposed rule.

Meter-Level Accuracy Assurance Requirements Should Not Fall Upon the Energy Purchaser

As described above, the Industry Trades believe energy purchasers should not be held responsible for accuracy attestations on behalf of energy providers. If an electricity purchaser does not purchase, maintain or monitor meters used for billing purposes, the burden of demonstrating that the meters meet the accuracy requirements of 40 CFR§ 98.24(b) should not fall upon the electricity purchaser; rather, the electricity provider should be responsible for this demonstration. The Industry Trades respectfully recommend removing the proposed requirements in 40 CFR § 98.24(a)(5) and (b) and requiring energy providers to report these certifications.

Alternatively, the Industry Trades recommend that the certification requirements found in 40 CFR §98.24(a)(5) and (b) should be provided by each electricity provider for all meters in the service area, rather than a certification on a meter-by-meter basis.

Meter-Level Recordkeeping and Reporting Requirements

As proposed, 40 CFR § 98.24(a)(2) requires reporters to collect a meter identifier and a photograph of each meter included in the MEMP. Collecting this information from hundreds or thousands of remote well pads, pipelines, and compressor stations, many of which are unmanned, will be extremely time consuming and ultimately may not be accurate. In many (if not nearly all) instances, and as indicated above, electricity purchasers do not own nor control the meters in use at a site; those meters may be replaced or changed by the energy provider without any notice to the electricity purchaser. Therefore, not only is this requirement extremely time consuming for the reporters, it would also fail to meaningfully improve the quality of reported data and the reported information could become outdated without the knowledge of the reporter.

Additionally, as proposed, 40 CFR 98.26(f) requires operators to report several pieces of data for each meter for each bill received. This requirement will be extremely burdensome while failing to increase transparency in reporting. For the oil and natural gas industry, this could require reporting hundreds, if not thousands, of individual meters. As described above, meters can be changed by the energy provider, with or without the purchaser's knowledge, throughout the course of the reporting period. Such meter changes could result in a Designated Representative (DR) certifying a report that may not be accurate as of December 31st of the reporting period[3]. As these meter numbers can change, requiring electricity purchasers to provide this level of detail does not increase EPA's ability to review or otherwise QA/QC the reported data, while still significantly increasing the burden of reporting on energy purchasers. Finally, the requirement to report meter location information to the county/city level can become very complex for facilities operating across a wide geographical area. The Industry Trades are respectfully recommending the removal of this reporting requirement.

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[3] As required in 40 CFR Part 98.4(e), each Designated Representative signs the following certification statement: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

EPA is also proposing reporters to include a "description of the portions of the facility served by the meter." As described above, this requirement would encompass hundreds of meters across a wide geographical area which could change with or without the purchaser's knowledge. This requirement is also burdensome at complex facilities, such as refineries, which may purchase electricity to supplement on-site electricity generation.

The Industry Trades believe these reporting requirements to be overly burdensome and ultimately do not increase the transparency or quality of reported data.

Submitting Sample Energy Bills

As proposed in 40 CFR §98.26, reporters are required to provide EPA with copies of one direct billing statement from each provider. The Industry Trades are concerned these statements could include confidential business information (CBI) relating to purchase agreements, rates, and thermal energy usage. It is also unclear why EPA needs reporters to submit these records; EPA does not have analogous requirements in other subparts to submit example raw data in the form of bills or invoices to validate the reported data.

Additionally, for operators with a large number of sites across a large geographical area, the proposal could require multiple providers to upload hundreds of pages of billing statements. As a practical matter, users of EPA's Electronic Greenhouse Gas Reporting Tool (EGGRT) have experienced delays in using the system when many reporters are using the system simultaneously; this seemingly simple task could result in very time intensive uploading requirements during a reporting period. Furthermore, as previously mentioned, reporters are not required to submit this level of documentation for other subparts, but instead follow the recordkeeping requirements codified in 40 CFR and the appropriate subparts. The Industry Trades support that same approach for Subpart B.

Allow Subpart W Reporters to Submit All Subpart W Segment's Energy Consumption at a AAPG Hydrocarbon Basin Level

The Industry Trades recommend that EPA allow reporters subject to reporting under Subpart W to report energy consumption for all GHG reporting activities within a single AAPG hydrocarbon basin without direct upload of billing statements. The Subpart W operations are often interconnected, and many operators report under production, gas processing and gathering and boosting segments. In addition, electric meters may service an entire basin, a single site, or multiple sites. In order to report at a source category level as defined in Subpart W, operators would need to allocate metered electricity to a single site and then reallocate back to a segment. This would be extremely burdensome and does not meaningfully improve the quality of reported data. This gives reporters the ability to maintain relevant energy consumption information in existing Greenhouse Gas Monitoring Plans, as already required in 40 CFR 98.3(g)(5) and other relevant subparts. As currently codified, this information would be available upon request by EPA.

Missing or Incomplete Billing Information

It is not uncommon for some billing information to not be finalized for up to six- months or longer. As a result, there could be instances where complete billing information may not be available by the reporting deadline for the complete prior calendar year. The Industry Trades request that EPA allow for the use of best information available or other reasonable estimation methods to estimate partial-year energy consumption when a full calendar year of billing is unavailable.

Renewable Energy Credits and Energy Consumption

As EPA has acknowledged in the preamble to the supplemental proposal, this method of reporting energy consumption does not provide the EPA with information on renewable energy credits (RECs) that allows reporters to net Scope 2 emissions commensurate with purchased and retired RECs. The lack of data collection and transparency on renewable energy attributes may inadvertently disincentivize the purchase of renewable energy altogether. The Industry Trades recommend that in addition to reporting the energy consumption, that EPA allows reporters to voluntarily report the amount of energy that is sourced from retired RECs or a renewable energy purchase agreement. This will provide the public and other stakeholders with a more complete picture of overall GHG emissions intensity.

Annual Data Only

EPA is proposing to collect data for every bill and every meter. For example, if the meter is billed monthly, EPA is requesting monthly data. The Industry Trades recommend that EPA remove any requirements to report data more granular than annual data. It is unclear how EPA could even use monthly purchased energy data to assess facility energy intensity. The onerous reporting requirements proposed in this new subpart indicates that EPA believes it can apply automatic checks to ensure all energy consumption bills are as expected and accounted for, the number of expected bills are reported (billing sequence), and that start dates and end dates align. However, given the wide range of energy providers, facility types, geographic locations and other factors, this assumption is incorrect. Bills are subject to billing corrections, rebills, negative usage bills to handle calibration errors, higher-than-previous usage to correct calibration errors; bills with zero usage to handle payment adjustments, overlapping start and end dates, some bills that cover two months instead of one, meters going into service, meters coming out of service, etc. It will be an enormous burden to report detailed information from every bill, EPA has not justified this effort, and EPA will likely burden reporters with error checking for very typical billing inconsistencies. For all of these reasons, EPA should collect annual data only.

Exempt Subpart B Reports from "Substantive Error" Provisions in 40 CFR Part 98 Subpart A

EPA's definition of "Substantive Error[4]", which would trigger resubmittal of applicable GHG reports, is overly broad for this subpart as it does not have a *de minimis* threshold. There can be adjustments to energy consumption records several months following the closing period of the billing cycle. These adjustments could result in an operator having to re-submit reports previously certified even if the adjustment does not result in a significant change in the reported energy consumption. This is especially problematic for the oil and natural gas industry because of the huge number of meters potentially subject to Subpart B, the large number of meters, adjustments, etc. which may not have a substantive impact on overall energy consumption. The Industry Trades request that EPA does not subject Subpart B reports to the "Substantive Error" provisions, as defined in 40 CFR Part 98 Subpart A.

Purchased Thermal Energy Reporting

As proposed, Subpart B requires reporting metered thermal energy products as well as comprehensive auditing requirements for thermal energy meters.

a. Consistent with the comments above, it is the Industry Trades' position that the purchaser should not be required to provide the most recent accuracy audit; instead, that should fall to the energy provider as the owner of the meter.

b. The Industry Trades object to the proposed requirement that a purchaser must conduct the audit on a thermal meter system where purchasing agreements do not include provisions for periodic audits under 40 CFR 98.24(c). Regardless of who is responsible for an audit on a thermal meter system, the Industry Trades request that EPA

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[4] Substantive error, as defined in 40 CFR 98.3(h) means, "an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified."

clarify minimum requirements to be considered a "qualified metering specialist" under 98.24(c) and any restrictions to using in-house resources (i.e., facility, energy provider, independent resources, etc.).

c. The Industry Trades request flexibility regarding the 5-year audit requirement for purchased thermal energy meters. As proposed, 98.24(c) states that if the audit has not been performed (or is older than 5 years old), the energy purchaser is to request an audit from the energy provider. However, this audit procedure can only be completed during a facility shut-down or plant turnaround. The Industry Trades request that EPA add language that allows for this audit to take place either every 5 years or during the next planned unit shut-down.

d. In 98.24(a)(6) and 98.26(j)(2), EPA is proposing that the reporter be responsible for developing a "clear procedure" and example of how measured data are converted to mmBTU. By putting the onus on the reporter to develop "clear procedures," the potential for a wide range in methods and results exists, thus calling into question the value and necessity of reporting thermal energy consumption. For example, there may be differences in how reporters quantify hot and cold energy products (i.e., positive vs. negative value), based on the purpose to add or remove thermal energy. As a result, some reporters may net thermal energy while others sum the absolute values, leading to very different results. The Industry Trades recommend that EPA clarifies how thermal energy measurements should be converted to mmBTU, and the Industry Trades also recommend adding a reporting field for both cold and hot energy products in the reporting form.

e. As proposed, Subpart B provisions for thermal energy reporting only address the purchased energy, which may not represent the energy consumed on-site. The Industry Trades propose reporting this information on a facility-wide net-energy basis. Many facilities that purchase steam also return condensate, which has embodied energy that is not consumed at the purchaser's facility. Also, some facilities that utilize electrical and/or thermal energy from a provider may pass through some of the energy purchased to a third party. In order for EPA to understand the energy consumed at the facility, both thermal energy purchased and condensate returned or energy passed through need to be understood. The Industry Trades believe that reporting this information on a net-energy use basis will provide clearer information regarding thermal energy usage.

f. The Industry Trades also request EPA to remove, or at least provide clarification/guidance regarding, the requirement to assign the decimal fraction of purchased energy to applicable GHGRP Subparts under 98.26(l) for larger integrated facilities that utilize multiple external electrical/thermal connections with on-site energy generating units or thermal production units, as it would be overly burdensome to reasonably segregate and calculate purchased energy from site generated energy with any reasonable confidence due to the fluid nature of imported and exported energy across a large facility. Similarly, guidance of scenarios on calculating excluded quantities under 98.26(j)(4) would be valuable for the regulated community as purchasing/selling of energy may overlap based on energy loading across the larger integrated facilities and surrounding community.

g. The definition of thermal energy that states "or any other medium used to transfer thermal energy and delivered to a facility" is overly broad and ambiguous. For example, it is unclear if purchased raw water utilized as cooling tower make-up water would be subject to the requirements, even though there may be no associated indirect emissions. The Industry Trades request clarification of the definition of thermal energy to only include thermal products where the primary reason for purchase is energy transfer and where energy was required to achieve a specific thermal property for the purchased products prior to metering. Similarly, the Industry Trades recommend incorporation of a reference temperature (e.g., outside of ambient) to define thermal energy products to avoid confusion.

h. Likewise, EPA's proposed definition of thermal energy also includes refrigerants. Clarification should be made that this excludes non-industrial process uses such as refrigerants for comfort cooling and food storage. In most cases these are not "metered," but this exclusion would avoid confusion. The Industry Trades respectfully recommend adding the proposed language ***in red*** below:

> ***"Thermal energy*** products means metered steam, hot water, hot oil, chilled water, refrigerant, or any other medium used to transfer thermal energy and delivered to a facility subject to this subpart. ***Thermal energy products do not include those used for non-industrial purposes such as comfort heating/cooling and food storage/preparation."***

Additional Comments Sought by EPA:

EPA is seeking comment on existing industry standards for assessing the accuracy of electric and thermal energy monitoring systems, the frequency of audits of these systems, and the accuracy specification(s) used for thermal energy product metering systems. Consistent with the Industry Trades' position on the meter-level QA/QC and accuracy requirements, the Industry Trades' members are not generally energy providers and cannot comment on the accuracy of electrical and thermal energy monitoring systems. However, it is the Industry Trades' position that any audits of these electric and thermal energy monitoring systems be performed only during a planned facility shut-down.

EPA is also seeking comment on their understanding that monitoring and recordkeeping systems are already in place for purchased energy transactions and on EPA's assessment that the incremental reporting burden would be minimal. As reflected in the comments in this section, the Industry Trades believe that the recordkeeping and QA/QC requirements as proposed would be extremely burdensome for operations across large geographic areas, such as oil and natural gas operations.

2. Subpart WW – Coke Calciners

The proposed Subpart WW includes two proposed calculation methods to determine the CO_2 emissions from coke calciners in section 40 CFR §98.493(a). The first method uses the Tier 4 method that requires Continuous Emissions Monitoring Systems (CEMS) and requires a stack flowmeter. Stack flowmeters on coke calciners can be unreliable and can be difficult to maintain while the unit is operating. Coke calcining units that do not currently have a stack flowmeter would need to purchase, install, maintain and calibrate them, which could be a cost in excess of the Capital and O&M costs given in Table 10 for an incremental burden.

The second method is a carbon balance based on the mass and composition of the green carbon feed, petroleum coke dust and marketable coke produced. Coke calcining units that do not currently weigh all of these streams or conduct regular sampling could be required to install new scales and collect and analyze samples which may again require expenditures in excess of the incremental burden costs estimated in Table 10. There may be issues getting the carbon mass to balance, as uncertainties in weights and coke composition could lead to under or overestimation of CO_2 emissions.

There is a third method, currently used at a coke calcining unit and currently used to comply with a Washington State GHG Reporting program, that should be included as an approved method in Subpart WW section §98.493(a). In this method a performance test is conducted to measure the stack flow while the CO_2 and O_2 concentrations are measured using a CEMs system, and either the green coke input or calcined coke output is weighed. The result of the performance test is to determine the coke calciner stack flow based on either green carbon input or marketable coke output. This allows the CO_2 emissions for each hour of the year to be calculated using the weighed coke input or output, the CEMs CO_2 and O_2 concentrations and the stack flow factor from the performance test. The performance test is conducted periodically and the factor from the last test is used until the next stack test is performed. The stack flow factor is corrected to a set excess oxygen concentration, and the CEMs data measured throughout the year to allow the measured CO_2 concentration to be corrected to the same excess oxygen concentration.

This third method combines elements from both of the methods currently included in the proposed Subpart WW. It has an advantage that use of a stack flow factor prevents potential large periods of data substitution when the stack flowmeter is not operating. The Industry Trades request that EPA add this third method to the proposed Subpart WW. The addition of an alternate State approved method is consistent with provisions that the EPA has previously made in the Tier 4 methodology in 40 CFR 98.34(c)(1)(iii) and 40 CFR 98.36(e)(2)(vii)(A) that allow a State approved monitoring program.

Summary

The undersigned associations, representing the oil and natural gas industry, appreciate EPA's willingness to collaboratively engage with the regulated community in order to improve the quality and consistency of reported data while also streamlining the reporting process. The comments provided in this letter are intended to support this effort by providing EPA with additional context and potential unintended consequences associated with some of the proposed reporting, recordkeeping, and QA/QC requirements.

The Industry Trades are working to reduce GHG emissions across the value chain of the oil and natural gas industry, and it is critical that the EPA and the GHGRP reflect accurate reporting of GHG emissions. To that extent, it is important that EPA carefully consider these proposed revisions and new subparts and consider the points outlined by the Industry Trades while considering future proposed rulemaking.

The undersigned associations encourage EPA to carefully consider the comments and recommendations contained within this letter, and we stand ready to respond to questions and provide further clarifications, as needed, from EPA. For more information, please contact Jose Godoy at Godoyj@api.org or 202-682-8073.

Sincerely

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ANNEX C: API Comments on EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023

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Submitted via regulations.gov

February 13, 2023

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W. Washington, D.C. 20460

Attention: Docket ID EPA-HQ-OAR-2021-0317

RE: Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Including Appendix K and Social Cost of Greenhouse Gases

Dear Administrator Regan:

The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (87 FR 74702, December 6, 2022) ("Supplemental Proposal"). This submittal includes comments on the associated Appendix K proposal and EPA's "Report on the Social Cost of Greenhouse Gases".

API is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. Gross Domestic Product (GDP). API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators, and marine transporters, as well as service and supply companies, providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

As we indicated in our comments on EPA's November 2021 Proposal (86 FR 63110, November 15, 2021), API supports the cost-effective, technically feasible, direct federal regulation of methane from new and existing sources across the supply chain. We appreciate EPA's further development of a fugitive emissions monitoring framework that allows for use of advanced detection technologies. We also appreciate EPA's recognition that Appendix K's monitoring protocol is not appropriate for the upstream production and transmission segments. While we appreciate EPA's responsiveness to many of the issues raised in our comments[1] on the November 2021 Proposal, nevertheless, we have serious concerns regarding the cost effectiveness, technical feasibility, and legal soundness of many aspects of the Supplemental Proposal. We also have extensive concerns with EPA's Draft Report on the Social Cost of Greenhouse Gases and the lack of transparency in the Interagency Working Group's process. Moreover, we strongly disagree with EPA's assertion[2] that November 15, 2021 can serve as the applicability date of the final rule for new, reconstructed, and modified sources.

Reducing methane emissions is a shared priority for EPA and our industry. We are committed to advancing the development, testing, and utilization of new technologies and practices to better understand, detect, and further mitigate emissions. In recent years, energy producers have implemented leak detection and repair (LDAR) programs, phased out the use of high-bleed pneumatic controllers, and reduced emissions associated with flaring – voluntarily and under federal and state regulations. Voluntary, industry-led initiatives such as The Environmental Partnership[3] have built on the progress industry has made to reduce emissions and continuously improve environmental performance. Since its founding in 2017, the Partnership has grown to include over 100 companies representing over 70% of total U.S. onshore oil and natural gas production.

The New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc are complex rules that will apply to hundreds of thousands of facilities owned and operated by these and other companies, including many facilities that have not previously been subject to regulation under the Clean Air Act. Because of the wide variety of conditions faced by these facilities, the novel nature of a first ever existing source rule, and timing of the Supplemental Proposal's release and subsequent overlap with the holiday season, API requested[4] an extension of the comment period to allow additional time for our staff and our members to fully review the Supplemental Proposal and provide EPA with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. As we noted, API members who are engaged on this issue have been concurrently engaged in reviewing additional recent legal and regulatory developments on this subject matter. We regret that EPA did not grant the request and may rush to completion of a final rule that does not reflect the full measure of consideration necessary to ensure cost effectiveness, technical feasibility, and legal soundness.

In our review of the Supplemental Proposal, API once again considered the effectiveness of emission reduction strategies, safety, feasibility, operability, and cost. Where appropriate, we have recommended changes to the regulatory text that will enable the final rule to meet these critically

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[1] EPA-HQ-OAR-2021-0317-0808
[2] 87 FR 74716
[3] http://www.theenvironmentalpartnership.com
[4] EPA-HQ-OAR-2021-0317-1588

important criteria. We have also detailed the necessity of workable implementation timelines that consider the supply chain and labor constraints facing our industry, constraints which will be exacerbated as the final rule takes effect. The adoption of the recommendations in our comments in the final rule would reflect a more cost-effective and technically feasible regulation of methane.

API appreciates EPA's engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize a cost-effective rule that incentivizes innovation, advances the progress made in reducing emissions and addressing climate change, and ensures that our industry can continue to provide the world with the affordable, reliable energy it requires.

If you have any questions regarding the content of these comments, please contact Ryan Steadley at steadleyr@api.org.

Sincerely,

cc:

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Peter Tsirigotis, EPA
David Cozzie, EPA
Karen Marsh, EPA
Steve Fruh, EPA
Amy Hambrick, EPA

API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"

(Proposed NSPS OOOOb, EG OOOOc, Appendix K and the Social Cost of Greenhouse Gases)

Docket ID: EPA-HQ-OAR-2021-0317

February 13, 2023

Executive Summary

The American Petroleum Institute (API) supports certain aspects of the Supplemental Proposal for New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc and remains committed to working with the Environmental Protection Agency (EPA) and the Administration to identify cost-effective emission control opportunities. The comments provided herein focus on legal, technical, and feasibility challenges with specific provisions that EPA included within the Supplemental Proposal of NSPS OOOOb and EG OOOOc. Listed below are API's primary concerns with the proposed rules.

To facilitate review of our comments, API has summarized these concerns and provided reference to the detailed comments where additional supporting discussion has been included. Our members look forward to continued dialogue and engagement as EPA works towards finalizing these important rules.

1) **The Applicability Date for NSPS OOOOb should be December 6, 2022.**
The Clean Air Act (CAA) Section (§) 111(a)(2) definition of "new source" uses the term "proposed regulations" in defining the new source trigger date. The November 2021 preamble alone cannot constitute a proposed rule any more than a final rule that is unaccompanied by regulatory text could be declared a "rule." Although the November 2021 preamble described the type of regulatory requirements that EPA contemplated promulgating, the preamble was not in and of itself a document that establishes the "agency statement of general or particular applicability and future effect." That type of required statement would be established only by the proposed regulatory text, which was not provided until the December 2022 Supplemental Proposal. Many of the requirements included in the proposed regulatory text could not have been gleaned from the prior descriptions provided. Refer to Comment 8.1 and Comment 12.1.

2) **Adequate implementation time must be provided for NSPS OOOOb and EG OOOOc.**
NSPS OOOOb and EG OOOOc will apply to hundreds of thousands of sites when implemented. Our members are already experiencing a noticeable delay in the supply chain for equipment required by the proposed rules including (but not limited to) control devices, flow monitoring equipment, instrument air systems, solar panels, etc. Control devices are currently experiencing delays of 3 to4 months, while flow monitors are on backorder for a minimum of 6 to8 months from suppliers. Instrument air systems (including the air compressor and associated equipment) are nearly 1 year on backorder, and recently ordered solar panels are delayed between 18 to24 months. As more facilities become subject to proposed requirements in NSPS OOOOb and EG OOOOc, the above timelines are anticipated to be exacerbated before the market experiences a correction to meet these new levels of demand. We provide more detail related to current supply chain delays in Comment 5.2 and Comment 7.1. We request EPA consider these challenges prior to finalization of certain provisions within these rules to allow operators the ability to acquire and install the required equipment. Additionally, EPA should allow more time for new, modified, and reconstructed sources to come into compliance with NSPS OOOOb if it maintains the current applicability date of November 15, 2021.

3) **Associated gas provisions need to be significantly modified.**
Whereas API supports and recognizes the environmental benefit of eliminating the venting of associated gas from oil wells, EPA must recognize the distinction between associated gas from oil wells that route to a sales line and oil wells that do not have adequate or accessible gas gathering infrastructure. Removing wells connected to sales lines (or recovering gas for another primary purpose) from the requirements of the associated gas provisions would help to eliminate confusion resulting from EPA introducing its own interpretation of "flaring" when multiple definitions of "routine flaring" already exist in state and voluntary programs. Additionally, API does not support the requirement to make an infeasibility demonstration, along with safety and technical certifications in order to flare associated gas. Refer to Comment 4.0. and Comment 12.9.

4) **As proposed, the Super-Emitter Response Program presents numerous legal, logistical, commercial, safety, and security risks that have not been adequately considered by EPA within the Supplemental Proposal.**
To address these concerns (and assuming EPA resolves the legal deficiencies), numerous adjustments to the proposed framework are necessary. Specifically, EPA must establish requirements for monitoring of third-party data, provide a formal notification process that includes EPA involvement and review, and provide limitations on how any monitored data is released and used publicly. Refer to Comment 1.0, Comment 12.3, and Comment 12.4.

5) **In determining storage vessels affected facility Potential to Emit, EPA's proposed criteria for legally and practicably enforceable limits have broad legal implications and pose several permitting challenges.**
The proposed criteria and the additional methane emissions threshold may be lacking in existing permits that have previously been understood to be legally and practicably enforceable and may also be impossible to obtain under existing permitting mechanisms. EPA should continue to defer to the states on sufficient monitoring, recordkeeping, and reporting requirements to include in permits to establish legally and practicably enforceable limits. API also offers suggestions concerning various definitions and proposed control requirements for storage vessels affected facilities. Refer to Comment 6.0. and Comment 12.10.

6) **As proposed, alternative technology requirements for fugitive emissions monitoring, including continuous monitoring, are impractical and may disincentivize the use of this emerging technology.**
API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA to make key adjustments in the final rule to enhance the use, and not unintentionally disincentivize development and deployment of these technologies. In particular, we believe there should be approved technologies for operators' use at the time the rule is finalized, alternate technologies should not be held to a greater level of stringency (i.e., frequency) than Best System of Emission Reduction (BSER) as currently proposed, and EPA should streamline the timeline and actions to conduct repairs. Refer to Comment 3.0.

7) **API proposes AVO inspections only at multi-wellhead only sites.**
EPA's focus on finding large fugitive emissions at single wellhead only sites using audio, visual, olfactory (AVO) inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall

well site emissions. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Refer to Comment 2.1.

8) **EPA should clarify its preamble language concerning leaks detected from a cover or a closed vent system during associated inspections or other fugitive emissions monitoring.**
Emissions detected from covers and closed vent systems do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented. Like standards for other fugitive emissions components, the "no identifiable emissions" standard is a work practice standard rather than a numerical emissions standard. Therefore, EPA must make it clear that a cover or closed vent system remains in compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed. Regarding control devices, API recommends a compliance extension of at least one year for the proposed monitoring requirements. We also offer suggestions to provide consistency between manufacturer-tested devices and other enclosed combustion devices as well as request EPA provide the necessary monitoring alternatives given the increased number of control devices subject to proposed monitoring requirements. Refer to Comment 5.0.

9) **EPA should amend many of the provisions within the Supplemental Proposal to work practice standards and eliminate the additional technical demonstrations with accompanying certification statements.**
EPA has added several certification statements throughout the proposed requirements for NSPS OOOOb and EG OOOOc – including certifications for pneumatic pumps, gas well liquids unloading operations, and associated gas from oil wells. EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating exceptions that require technical demonstrations and engineering certification. Inclusion of these technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA § 111 because non-emitting standards are not "adequately demonstrated" if exceptions are needed to make them feasible and workable. Regarding the certification statements themselves, a certified official is already required to sign the report certifying the company's compliance with all applicable provisions. These additional certifications should be removed prior to finalization of these standards for associated gas from oil wells, pneumatic pumps, and gas well liquids unloading operations. Refer to Comment 4.1, Comment 8.2, Comment 9.1, Comment 10.1, and Comment 12.9

10) **Requirements for pneumatic controllers and pneumatics pumps should be simplified and aligned.**
While we support EPA's proposal for defining the affected facility for both pneumatic controllers and pumps as the collective, we have numerous concerns with the practical and logistical aspects of how EPA has outlined control standards between the two sources. Specifically, EPA has proposed a completely distinct set of requirements for natural gas-driven controllers separate from natural gas-driven pneumatic pumps with sometimes conflicting statements made to justify EPA's decisions. The requirements for both pneumatic controllers and pumps should be streamlined for consistency with neutral technology standards that do not require additional certifications and allow for emissions to be routed to a control device. Refer to Comment 7.0 and Comment 8.0.

11) **EPA should streamline the recordkeeping and reporting requirements associated with compliance assurance of the proposed rules.**
EPA should continue to streamline both recordkeeping and reporting as it relates to these proposed requirements to include only the necessary information that will help assure compliance. Streamlining is especially critical for locations with existing sources as the cumulative impacts for tracking records are anticipated to be much larger than EPA estimates and will apply to hundreds of thousands of sites across the U.S. For some sources, EPA has described requiring records and potential reporting of information that does not link directly to emission controls or work practices, which API does not support. We support inclusion of recordkeeping and reporting that help demonstrate compliance with less administrative burden. Refer to Comment 9.3 and Comment 13.2.

12) **EPA should grant equivalency for state programs across emission sources for NSPS OOOOb and EG OOOOc.**
Given EPA has described many requirements that are consistent with those at the state level (e.g., Colorado, New Mexico, and California), EPA should allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb and EG OOOOc where it is appropriate to do so for leak detection and repair (fugitive emission monitoring) and other emission control provisions. EPA should allow states the opportunity to demonstrate programmatic equivalency, including addressing deviations from the form of the proposed standards. Without this, states and operators may be administering and complying with two sets of requirements (standards and administrative) that are duplicative because they are intended to achieve similar goals but are not perfectly identical. It also precludes innovative regulatory approaches from states. Refer to Comment 12.6 and Comment 12.7.

13) **EPA should carefully consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc in conjunction with the cumulative burden imposed through provisons in the Supplemental Proposal.**
EPA must consider the cumulative burden imposed to the regulated community of numerous and onerous provisions in the Supplemental Proposal, especially due to the unprecedented number of sources that will be subject to the rule given the proposed November 2021 applicability date for new, modified, and reconstructed sources. EPA must also consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc and the difficulty the industry has faced to fully understand the impacts of this rule without a comment extension. These difficulties for the regulated community have been compounded by other rules that impact the same sources (e.g., Bureau of Land Management's (BLM's) Waste Prevention Proposal). Specifically, EPA needs to be clear on the disposition of NSPS OOOO and OOOOa applicable sources if and when they become subject to EG OOOOc. Finally, EPA must revise its Regulatory Impact Analysis, including the potential for lost production stemming from implementation of these rules. Refer to Comment 12.1 and Comment 12.5.

14) **For equipment leaks at onshore natural gas processing plants, API recommends that closed vent systems be monitored annually and that appropriate VOC and methane concentration thresholds be established for applicability.**
While API supports the proposed bimonthly OGI monitoring as well as the proposed alternative monitoring based on the incorporated NSPS VVa requirements with simplifications, we have concerns with the proposed frequency for closed vent systems and the proposed potential to emit applicability threshold for VOC. While we generally support the proposed Appendix K for OGI monitoring at gas plants, we have several comments regarding proposed Appendix K as provided in Attachment A. Other

comments on leak detection and repair at gas plants include our recommendation on the proposed definition of equipment for capital expenditure evaluations. Refer to Comment 11.0 and Attachment A.

15) **API appreciates EPA's decision to accept comments specifically on the EPA's Social Cost of Greenhouse Gas (SC-GHG) Report, but we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates.**
API shares the Administration's goal of reducing economy- wide GHG emissions. With respect to SC-GHG our concerns stem from the approach taken by EPA, including the anticipated role of these new estimates in EPA's rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group. Refer to Comment 13.5 and Attachment B.

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Attachment A – Responses to EPA Solicited Comments for Use of Optical Gas Imaging in Leak Detection

Attachment B – Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

PROPOSED NSPS AND EMISSIONS GUIDELINES FOR THE OIL AND NATURAL GAS SECTOR (NSPS OOOOb AND EG OOOOc) INCLUDING APPENDIX K
DOCKET ID: EPA-HQ-OAR-2021-0317

While we have made every effort to thoroughly review both proposed New Source Performance Standard (NSPS) OOOOb and Emission Guidelines (EG) OOOOc as we formulated these comments, there may be places where we only provide a citation or reference as it pertains to proposed regulatory text in NSPS OOOOb. Unless we have provided a distinctly separate comment as the topic pertains to EG OOOOc, we also intend the comment to apply to proposed EG OOOOc. Additionally, when using the terms “proposal” or “standards” in these comments in reference to the November 2021 preamble, it does not constitute a “proposed rule” or “emission standard” for purposes of triggering applicability under CAA § 111(a)(2).

1.0 Super Emitter Response Program

As proposed, the Super Emitter Response Program (SERP) presents numerous legal[5], logistical, commercial, safety, and security risks that have not been adequately considered by the EPA and are the basis for the comments we offer herein. These complex issues would benefit from further discussions between EPA, operators, and other interested parties.

Our members understand the importance of identifying and addressing large emissions events and any future support for a program would be grounded in a shared interest to reduce the incidence of these emission events. For over three decades, EPA and industry have successfully collaborated on the implementation of voluntary programs to reduce methane emissions from the oil and natural gas sector under both the Natural Gas Star and Methane Challenge Programs. While we believe the SERP may be better suited to function as a voluntary based program, API members recognize the intent of the EPA to create a useable and workable program that identifies these large emissions events from a variety of stakeholders.

We encourage EPA to conduct additional outreach on the proposed framework and repropose a program that meets all Clean Air Act legal requirements prior to finalizing the requirements (as provided in §60.5371b). Our members would welcome the opportunity for future discussions on this important topic.

1.1 API proposes a programmatic framework that is managed by EPA and incentivizes the finding and subsequent repair of potential super emitter emission events.

EPA has described the SERP as a backstop to the requirements of NSPS OOOOb and EG OOOOc. However, as we describe throughout our comments there are serious legal, logistical, commercial, safety, and security problems inherent in EPA’s proposed program. The framework we have described herein achieves the goals EPA has described for the program while addressing the concerns API members have with EPA’s proposal.

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[5] See Comment 12.3 and 12.4 of this letter for a discussion of the numerous legal deficiencies underpinning the proposed SERP.

For the SERP to be effective, EPA must reconsider the operational flow of how the program will function and be implemented. This framework includes adding formal notifications first from third parties to EPA and then from EPA to operators. We also specifically offer suggestions on clear timelines for all participants of the program where information can be transferred in a clear and transparent order, which we have emphasized in our framework.

Below we have outlined our suggestions on the appropriate steps to be included in a reproposed framework, which provides greater confidence that the data provided under the program will be valid, actionable, and achieve EPA's goals for transparency within the program.

1) The third party completes approval certification process by EPA for inclusion in the Super-Emitter Response Program and becomes "certified or re-certified".
2) Certified third party[6] notifies EPA of planned monitoring, including submittal of a monitoring plan, at least **30 business days** prior to planned monitoring. Depending on technology deployed, such as satellites, this pre-approval may include flight plans for extended time periods. The components of the monitoring plan are more fully described in Comment 1.1.3 of this letter.
3) EPA reviews the certified third parties' monitoring plan for approval or disapproval.
    a. If approved, EPA notifies the impacted operators at least **7 business days prior** to monitoring with details of the monitoring to be conducted including technology planned for use, dates of monitoring, flight paths (if appropriate), etc. This notice essentially acts as a "pre-notification" to operators, which enables the operator to have staff available to ensure safety of operations, if warranted based on technology that will be used to detect potential emissions by a third-party.
    b. This "pre-notification" may also help both EPA and the third-party identify the appropriate operators, including the correct contact information, in the event a super emitting emissions event is detected. The potential for incorrect identification of operators is of concern for our members.
4) Timing of notification of results of monitoring to the operator is critical to the effectiveness of the SERP. After monitoring is completed, third party has **2 calendar days** to provide data as defined in §60.5371b(b) to the EPA.
5) If EPA determines the data provided by the third-party to be credible and warrants investigation, EPA provides data for any super emitter emission event to the appropriate operator(s) within **3 calendar days** of verification of third-party monitored data.[7]
6) Operator(s) will initiate an investigative analysis **within 5 business days** of receipt of data from EPA and complete the investigation within **10 business days** of receipt of the data from EPA.
    a. Given how certain technology is applied, the detection may not be from the facility that was notified, may be a permitted release, may be due to maintenance activity, or another reason that does not require action (such as monitoring data calibration issue). If the emissions event was the result of a permitted activity or could not be validated after full investigation by the operator, the

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[6] For the purpose of these comments when we reference a 'third-party', "certified notifier" or 'certified third-party' we mean the certified individual and the monitoring company whose technology is utilized to conduct monitoring.

[7] The basis for the timing proposed in steps 4 and 5 is to align with what EPA has proposed for operators using similar technology.

operator will provide "no action required" demonstration to EPA as specified in §60.5371b(c)(8) and §60.5371b(e)(1).

b. If the emissions event was result of component failure or other equipment defect, the operator(s) will complete final repairs **<u>within 15 calendar days</u>** after completing the investigative analysis.

7) All public information should be published by EPA only. EPA should manage all data that is to be public and establish a protocol for when and what type of specific details of a potential super-emitter emissions event is published via EPA's proposed website per §60.5371b(e)(4). We strongly disagree with the assertion in Section IV.C.2.a of the preamble (87 FR 74750) which states "*The EPA would then promptly make such reports available to the public online. Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting.*" Given that much of the data collected can be interpreted incorrectly and not aligned with operating conditions, the EPA should be the only authority to publish data, and EPA should publish data only after operators have had an opportunity to review and respond to the information and EPA has fully reviewed and vetted follow-up actions with the operator.

The timing of each step in the above framework has been crafted with the intent that all participants are held to timelines that are workable and suitable for each step of the framework. Operators are concerned they could receive multiple third-party notifications with limited time and resources to respond appropriately if stricter timing criteria for third parties to provide data is not established. The above framework seeks to address this concern.

1.1.1 EPA should establish transparent certification requirements for third-party monitoring.

Two-way accountability will allow for efficient and effective execution of the super-emitter response program. EPA should develop a clear set of criteria (e.g., in a checklist form) that any certified third-party would need to meet to participate in the program. This certification is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. We appreciate the demonstration for third-party notifiers as outlined in the preamble (87 FR 74750), but do not believe the requirements as proposed in §60.5371b(a) provide enough stringency. Considering the requirements EPA has established for an operator, the same level of scrutiny should also be expected of the third-party data provider when using the same technology. Strict criteria should be established covering the following:

- An expectation from EPA that third parties and their approved detection technologies must be re-certified on a specified frequency. This certification process should be similar to other EPA certifying programs (e.g., EPA auditor).

- An expectation for third parties to attend EPA-specific training, including the do's/don'ts as well as what they are authorized to do or not do – including the handling of data they plan to use within the program.

- Clear criteria for what type of actions may immediately make data collected invalid and/or fully revoke a third party's participation in the program. Regarding EPA's proposed revocation of third party certification (87 FR 74750), we recommend that the criteria for revocation explicitly state that upon a third party's third submission of verifiably false data from any combination of operators or sites, or upon trespass or otherwise unlawful or unauthorized entry to a facility, or vandalizing energy infrastructure, or upon unauthorized distribution or publication of data gathered under the program, the offending third party

shall have their certification revoked for a period of no less than three years. Any data gathered at the time of a trespass would render that data invalid.

1.1.2 The super emitter response program must have a transparent and formal notification process where EPA manages the flow of information from the third-party to the operator.

As similarly done with other EPA programs, formal notification to facility owners/operators (and even with the third-party) could potentially be via email or a central online-based system.[8] The process should allow EPA to confirm that the correct operator received the notification and follow-up if the operator does not respond within a certain timeframe. There are also concerns with measurement of emission events, including pin-pointing sources or facilities correctly (especially when there are adjacent facilities in proximity to each other or sharing boundaries), and in conjunction with the minimum resolution of the monitoring technologies.

Some additional considerations include the following:

- **Operators should be given advanced notice of planned third-party activity. As proposed, the response burden for operators is not predictable and operators are unable to properly plan and schedule resources.** If timing and location of surveys are unknown to a facility owner/operator, operators will have no indication of when and how much resources to have available. This is important to promptly evaluate data and implement corrective action if necessary. Third parties may employ technologies, like aerial surveys which can result in multiple detections in a short amount of time. It's not unreasonable to expect that surveys may be conducted by multiple third parties simultaneously or in series, and conversely, there could be extended periods of no third-party activity. Program requirements must balance the needs of operators to plan for both day-to-day operations and promptly prepare for and respond to third-party activity.

- **Detections of potential super-emitter emission events should be shared with the operator within a certain time period from detection to allow for effective and prompt response to reduce the emission impact.** As proposed, third parties only have to provide data *"as soon as practicable to the owner or operator"* under §60.5371b(b)(7). Since there could be many days between when monitoring occurred and when an operator receives the survey data, an investigative analysis may not find any significant ongoing / persistent emissions event. Furthermore, third-party notifiers could attempt to overwhelm a single operator with a rush of data from multiple monitoring campaigns (e.g., using remote-sensing equipment on aircraft) that would be untenable to fully investigate.

We propose suggested timing for these notifications in Comment 1.1.

1.1.3 Monitoring conducted by a third-party should be pre-approved and accepted by EPA prior to execution of the data gathering event.

There are clear protocols, including monitoring plans, that operators are required to have in place to conduct emission monitoring data. Any certified third party that conducts monitoring must be held to the same stringency

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[8] If an online-based system is chosen, there will be an additional resource / cost burden on EPA to develop and maintain the functionality of the system. Also, there may be an issue when operators are in close proximity to each other and have shared property boundaries, or when a facility was owned by a specific operator at one time but has been sold to another owner.

as an operator if they were to use the same technology. This reciprocity is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. It also is necessary, given that third-party monitoring would create enforceable legal obligations for affected/designated facilities as currently proposed. There is nothing under the law that, in and of itself, prevents any third party from conducting remote monitoring (as noted elsewhere, the law may impose restrictions on where/when/how such monitoring may be done; for example, third-party monitors may not trespass on private property). But when such monitoring has regulatory consequences, it would be arbitrary and fundamentally inconsistent for EPA to set more lenient criteria on third-party monitors than it does for similar monitoring required to be conducted by affected/designated facilities.

At least 30 business days in advance of the planned monitoring campaign, the third-party must submit a monitoring plan to the EPA for approval. The monitoring plan submittal should include the following information (at a minimum):

- Site coordinates and/or map of the area to be monitored;
- Description of monitoring equipment to be used to conduct the activity;
- Documentation of emissions detection limit;
- Proposed starting date and duration of the monitoring activity;
- Contact details (e.g., name, phone number, title) of third-party contact person;
- Name and details of owner of remote monitoring equipment;
- Quality assurance / quality control plan, including calibration procedures, if applicable to the technology (Subsequently, the third-party should also have to demonstrate how it met its monitoring plan for each monitoring event when monitored data is submitted to EPA);
- Specification on how the data will be provided and in what timeframe to the EPA; and
- Certification statement signed by an authorized company official attesting that the third-party will conduct monitoring activities in accordance with EPA requirements.

With the 30-day approval period, it would also allow EPA sufficient time to provide affected facility owners / operators notice of the upcoming monitoring event, which should be provided at a minimum 7 business days prior to the start of the monitoring field event.

1.1.4 There are safety and security concerns with third parties trespassing on private property.

Even though EPA notes in Section IV.C.2.a of the preamble (87 FR 74749) that it considered concerns for the safety of individuals engaged in third-party monitoring and of facility operator personnel, there are still tangible safety concerns related to the use of certain monitoring technology by third parties (e.g., mobile monitoring platforms) to identify super-emitter emissions events. Some operators have experienced public individuals driving through operator sites (especially in remote locations with no “fencing”) with vehicle mounted monitoring devices, which is especially problematic as access can typically be obtained by road, some of which may be private

roads. There have also been issues acknowledged between private third-party landowners and trespassers, which can be another point of contention.

Personnel working at our facilities are required to undergo numerous hours of training to safely perform their work duties, including but not limited to wearing the correct personal protective equipment based on site conditions, exposure to extreme heat or cold weather, biologic hazards such as snakes or other critters, specific training on how to navigate rotating equipment, and where and how to identify hazardous chemicals/gas. For example, training specific to the presence of hydrogen sulfide (H_2S) includes hazards, symptoms of exposure, detection devices, and how to safely walk away from exposure.

Individuals require site specific training to be present at any given facility and there is potential liability (to both the individuals and to company assets) for individuals who do not have this training. The proposed SERP framework is geared to remote technologies, which by their nature should in no way necessitate third-party representatives to appear at facilities. API recommends that any information that is collected by a third party that is outside of an EPA-approved monitoring campaign, where EPA and/or operators have not been notified in advance of the data gathering campaign, be considered invalid. As we also provided in Comment 1.1.1 , trespassing (such as driving through a site) should immediately result in revocation of a third party's certification and render any information gathered at the time invalid.

1.1.5 The EPA should clearly manage how third-party monitored data is published in conjunction with corrective actions taken by operators.

Participation in the regulatory process through the super-emitter response program by EPA-certified third parties must include limitations on the ability of those third parties to use the information gathered under the program for any other purpose. Such limitations must include requirements that the third party (and the monitoring companies they contract) maintain the security and confidentiality of data collected during SERP monitoring, where the monitoring results cannot be independently published (via website or social media). EPA has a fundamental role to play in the validation of third party collected data, which extends to the publication of such data. When a third party accepts the responsibility of participating as a certified notifier, they accept this role and handling of data.

- **Monitored data should not be published without context from operator feedback or corrective actions.** EPA's state within the preamble (87 FR 74750) "*owners and operators would have the opportunity to rebut any information in a notification provided by the qualified third parties in their written report to the EPA, by explaining, where appropriate, that (a) there was a demonstrable error in the third party notification; (b) the emissions event did not occur at a regulated facility; or (c) the emissions event was not the result of malfunctions or abnormal operation that could be mitigated.*" While we agree with this concept, the proposed framework does not provide the same level of assurance that these rebuttal statements would be linked to the third-party monitored data directly in the public forum without EPA intervention. If the data is posted on other public websites, there is a chance any resolution/follow up comments and descriptions from operators will not be carried over to the non-EPA sites, therefore resulting in inaccurate presentation of the facts. While we concur that data transparency is valuable, and share the goal of disseminating information to mitigate emissions events, these goals must be balanced with adequate considerations for national security risks, reputational risks (e.g., incorrect operator maligned in media, third party is not approved or certified by EPA, permitted events are taken out of context, etc.), and stakeholder risks.

- **EPA should establish a protocol or annual publication updating on progress of the program.** We believe the current language proposed in §60.5371b(e)(4) establishing a new EPA website is extremely flawed and ambiguous. Third-party monitored data on its own will provide very limited context for the general public and can be easily taken out of context. We believe a synthesized annual report or fact sheet published by EPA would offer a clearer depiction of relevant details with full context around super emitters including but not limited to: how many third-party monitoring events took place, the number and location of valid super emitter emission events that were detected, the number of super emitter events that were permitted or authorized emissions, the rate of erroneous notifications and the types of corrective actions that were taken to repair other super emitter emissions identified. Operator related information could remain anonymous in this annual report, unless EPA found specific operators to be conducting insufficient corrective actions or operators that do not acknowledge EPA's notification attempts regarding the monitoring campaigns (and EPA has verified the correct operator and contact information).

  At a minimum, EPA should limit the information for super-emitter emissions events so that the information cannot be misconstrued or used to publicly attack operators in the media; especially operators who are proactive participants within the SERP. The shared goal of finding these leaks and fixing them as expeditiously as possible should remain at the forefront and in conjunction with transparency objectives.

1.1.6 An "investigative" analysis should be conducted in conjunction with initial corrective actions.

As we explain further in Comment 3.2, the EPA outlines in §60.5371b(c) specific actions to take place if a super-emitter emission event occurs. API supports investigating the source and cause(s) of significant emissions events that are brought to an operator's attention Through the process described in our comments. We agree that EPA's investigative actions listed §60.5371b(c) are appropriate and practicable as far as investigating and conducting initial corrective actions for super emitter events. However, EPA's use of the term "root cause analysis" is problematic and ambiguous. The concept of "root cause analysis" is embedded in numerous other regulatory and non-regulatory programs and has varied meaning and purpose in each application. Thus, use of that term here does not clearly and adequately define the scope of the legal obligation, which will make it difficult for operators to understand what must be done to comply and will invite dispute and controversy if/when this program is implemented. To address this concern, we recommend the actions EPA has outlined be maintained, but the term supplied as the definition for those actions be changed to "investigative analysis" as it relates to super-emitters in §60.5371b(c).

1.1.7 After an investigative analysis has occurred, an operator should have the ability to designate the emission event as "no action required," as applicable.

Since the source of an emission detection during a monitoring campaign could be the result of various situations (and even EPA acknowledges that there may be demonstrable errored data), API suggests that the EPA include a pathway for operators to simply identify situations where "no corrective action required" beyond what has been proposed in §60.5371b(e)(1). These additional situations could include 1) the wrong operator was notified; 2) where the emission event cannot be validated by the operator; 3) there was a demonstrable error in the third-party notification; (4) the emission event did not occur at a regulated facility (e.g., well site or compressor station); or 5) the emission event was authorized as authorized or permitted operations. The information an operator should submit back to EPA should be simplified for planned or authorized emissions. Further, within

§60.5371b(e)(1)(iii), EPA must clarify that the applicable standard is limited to the applicable standard of this subpart.

1.1.8 Safe Harbor for Operators

The presence of a super emitter emission event does not necessarily indicate a standard has been exceeded or that a violation has occurred. Moreover, any documents shared with EPA articulating corrective actions taken should be subject to a safe harbor provision that prevents EPA or any other entity from using the information in the document for purposes of enforcement / notice of violation (NOV), civil suit, etc.

1.1.9 The role of states as a delegated authority within the super emitter proposed framework is unclear.

Throughout the preamble EPA uses language that mentions state agencies as delegated authorities. One such example is found at 87 FR 74750, *"The EPA further proposes that the entity making the report shall provide a complete copy to the EPA and to any delegated state authority (including states implementing a state plan) at an address those agencies shall specify."* The role of state agencies within the SERP must be more adequately defined. For example, as explained in these comments, the SERP program is not lawful or practically workable unless EPA takes a direct role in implementing the program (e.g., EPA must review and approve site-specific third-party monitoring plans, EPA must receive and vet the results of third-party monitoring and must decide whether the results are actionable). In the final rule, EPA must explain the process and degree to which these functions may reasonably be delegated to the states and, for functions that EPA determines are delegable, provide mechanisms to assure consistency among EPA's and the delegated states' programs.

2.0 Fugitive Emissions at Well Sites, Central Production Facilities and Compressor Stations

API supports the retention of NSPS OOOOa requirements for optical gas imaging (OGI) monitoring at well sites, central production facilities, and compressor stations. Except for multi-wellhead only well sites (see Comment 2.1), API also supports the proposed audio, visual, and olfactory (AVO) and OGI monitoring frequencies. In addition to the following comments concerning requirements for fugitive emissions at well sites, central production facilities, and compressor stations, API notes that EPA is not providing a meaningful opportunity to comment on a key basis for removing the wellhead only exemption because the underlying data for the Department of Energy (DOE) study[9] is unavailable.

2.1 API proposes AVO inspections only for all wellhead only sites.

EPA's focus on finding large fugitive emissions at single wellhead only sites using AVO inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. As EPA has already concluded, AVO inspections are a useful tool at

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[9] Bowers, Richard L. Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859

sites that lack extensive background noise and have field gas containing mixtures of methane and VOCs and condensate or produced liquids (87 FR 74727)[10]. Not only do wellhead only sites match these criteria, but their emission points are closer to ground level compared to other sites. For these reasons, out of all well site configurations, AVO is expected to perform the best at wellhead only sites, and it generally can be applied more frequently than other leak detection methods. EPA appropriately concluded that *"the types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspection"* (87 FR 74729)[11]. Given the large number of wellhead only sites and EPA's focus in regulating fugitive emissions at these sites, quarterly AVO inspections are appropriate to detect fugitive emissions at any wellhead only site including single wellhead or multi-wellhead well sites.

The proposed leak detection method and frequency for any emission source should take into consideration the count and relative magnitude of emissions, among other factors. The number of wellhead only sites across the U.S. is estimated to be in the tens of thousands. The resource demand from any leak detection requirement on wellhead only sites using OGI or Method 21 quickly multiplies.

EPA notes that the DOE study "*demonstrates that fugitive emissions do occur from wellheads, and in some cases can be significant"* as the basis for regulating wellheads. Similarly, commenters indicated "the wellhead itself is a source of emissions" because "these well sites have other smaller equipment that leaks and malfunctions, with large emissions having been observed from these sites". While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall well site emissions. A study conducted over the Permian Basin determined that simple sites, such as wellhead only sites, experience median emission rates two orders of magnitude smaller than complex sites (0.03 kg/hr for simple sites vs 2.6 kg/hr for complex sites)[12]. CAMS contracted with Bridger Photonics to conduct aerial surveys performed in the Permian Basin (5,361 pieces of equipment on 1,450 facilities over 250 square miles). The project found that 2% of total detected emissions were from wells and 5% of total detections were from wells[13].

These studies demonstrate that the population average emissions from wellheads is not relatively significant and therefore chasing fugitive leaks from these sources will not be impactful compared to deploying resources to other contributing sources. Nevertheless, we recognize this does not preclude the potential for fugitive emissions from an individual wellhead. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Coupled with proposed requirements[14] for conversion to non-emitting pneumatic controllers at existing sites, the increased cost of additional OGI screening at these sites raises further concerns regarding premature shut-in of production and states' ability to preserve the remaining useful life of facilities.

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[10] On the other hand, AVO inspections are a useful tool for identifying when there are indications of a potential leak without the need for expensive equipment or specialized training of operators. For example, at sites that lack extensive background noise, a person would be able to hear if a high-pressure leak is present, which could present as a hissing sound. Field gas produced at well sites contains a mixture of methane and various VOCs, which have the potential to be detected by smell. Where the field gas contains a lot of condensate or other produced liquids, any resulting leaks would present as indications of liquids dripping or potentially puddles forming on the ground.

[11] The types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspections and would not require the use of OGI for identification. Therefore, the EPA evaluated a periodic AVO inspection and repair program for addressing fugitive emissions from single wellhead only well sites.

[12] Robertson, Anna M., 2020, New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, Environmental Science and Technology, 54(21), 13926-13934 https://pubs.acs.org/doi/10.1021/acs.est.0c02927

[13] https://methanecollaboratory.com/wp-content/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021_vFinal.pdf

[14] See Comment 7.0

EPA's basis for applying OGI to multi-wellhead only sites is centered around additional connection points and valves with generally smaller emissions (87 FR 74732)[15]. While this basis is true, the focus appears to be misguided. If the principal concern with a single wellhead only site is to find the rare, but possible, large emissions leak, then it should follow that the principal concern for a multi-wellhead only sites should also be the rare occurrence of large emission leaks because it is relatively more likely with more than one well-head. That is, what warrants more attention to a multi-wellhead only site should not be the potential for more small emission leaks, but the greater potential for a large emission leak. Any significant difference in emissions leak potential from a single wellhead only site versus a multi-wellhead only site is not likely to be because of a small emission leak.

More frequent monitoring may also be challenging since many existing wellhead only sites can only be reached on foot due to remote location and lack of lease road access. While we believe quarterly AVO is the appropriate frequency for all wellhead only sites, at a minimum, bimonthly AVO inspections only would also be acceptable as the monitoring requirement for multi-wellhead only sites.

2.2 The proposed definition of fugitive emissions component requires further clarification.

Several aspects of EPA's proposed definition of fugitive emissions component require further clarification.

- **In yard piping should not be included in the definition of fugitive emissions component.** The inclusion of in yard piping as a fugitive emissions component expands that definition in unprecedented ways. Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.[16]
- **Definition should include thief hatches or other openings on a controlled storage vessel only.** Monitoring thief hatches and other openings on uncontrolled storage vessels adds no environmental benefit since the storage vessel emissions will be the same whether they are emitted from the tank vent or through thief hatches or other openings. Combined with the next item, fugitive emissions component should include thief hatches or other openings on a controlled storage vessel that is not subject to NSPS OOOO, OOOOa, or OOOOb because of a construction/reconstruction/modification date on or before August 23, 2011, or a legally and practicably enforceable limit.
- **Definition should also include the appropriate references to NSPS OOOO and OOOOa.** As proposed, fugitive emission components include covers and closed vent systems and openings on storage vessels not subject to NSPS OOOOb requirements. Since EG OOOOc will be implemented over the coming years, the definition of fugitive emissions component should also include the appropriate reference to

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[15] Multi-wellhead only well sites. For wellhead only well sites with two or more wellheads, the EPA anticipates that the same large emissions source (i.e., surface casing valves) would be present. In addition to these valves on the wellheads have additional piping, and thus connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO.

[16] We note that EPA's rationale for adding yard piping to the definition of "fugitive emissions component" is that, "[w]hile not common, pipes can experience cracks or holes, which can lead to fugitive emissions." 87 Fed. Reg. at 74723. EPA explains that its proposal will "ensure that when fugitive emissions are found from the pipe itself that necessary repairs are completed accordingly." Id. EPA's proposal is vague and fails to provide an adequate opportunity to formulate meaningful comments because EPA does not explain how leak detection should be accomplished for "yard piping" as compared to other already-listed fugitive emissions components, where there are identifiable leak points (such as valve stems or flange interfaces) that are the target of monitoring. For example Section 8.3 of Method 21 (which applies to LDAR standards such as the one here that specify a concentration-based leak definition) explains that monitoring should be conducted "at the surface of the component interface where leakage could occur." Section 8.3 also includes detailed instructions for individual components (such as valves), where particular leak points are identified. In contract, there is no identifiable leak point for "yard piping" that reasonably would be the target of monitoring. In fact, using Method 21, there is no obvious way that the required monitoring could be conducted because of the expansive lengths of pipe where the sort of leaks that EPA seems to be concerned about might occur. Before finalizing a requirement to include yard piping in the definition of fugitive leak component, EPA must provide additional explanation of how the LDAR provisions would apply and provide an opportunity for public comment on that necessarily more specific proposal.

NSPS OOOO and OOOOa requirements. For that time period, a site could have storage vessels subject to NSPS OOOO or OOOOa and be subject to NSPS OOOOb fugitive monitoring. See Comment 12.5 regarding the proposed reconciliation of NSPS OOOO and OOOOa with NSPS OOOOb and EG OOOOc.

- **Existing clarifying language from NSPS OOOOa should be retained.** Since NSPS OOOOb proposes to allow natural gas-driven pneumatic controllers and pumps in limited circumstances (e.g., sites in Alaska without access to electric power), the existing language from the NSPS OOOOa definition should be retained to clarify what is considered fugitive emissions.

Based on the above clarifications, API offers the following suggested redline, which retains much of the current NSPS OOOOa definition, to the proposed definition of fugitive emissions component in NSPS OOOOb and EG OOOOc:

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411, §60.5411a, or §60.5411b, thief hatches or other openings on a controlled storage vessel not subject to §60.5395, §60.5395a, or §60.5395b, compressors, instruments, and meters~~, and in yard piping~~. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

2.3 Delay of repair requirements should be expanded.

Due to the hundreds of thousands of sites that would be subject to fugitive monitoring under NSPS OOOOb and EG OOOOc, EPA should expand the proposed delay of repair requirements in the following ways:

- **Consistent with the requirements for natural gas processing plants, EPA should allow for delay of repair due to parts unavailability.** NSPS VVa, incorporated by reference in NSPS OOOO and OOOOa for gas plants, allows for delay of repair beyond a unit shutdown if "*valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.*"[17] In the Preamble to the November 2021 Proposal[18], EPA recognized that operators of older equipment may experience delays in obtaining replacement parts. Given current supply chain issues and the larger number of well sites, centralized production facilities, and compressor stations, EPA should expand the current delay of repair requirements to include delays because of parts unavailability.
- **EPA should add other potential circumstances beyond an operator's control that would require a delay of repair.** Repairs may be delayed due to circumstances not currently listed in the rule. Specifically, there are seasonal constraints related to farming and/or endangered species where operators cannot bring a rig in or have surface disturbance. Delay of repair should be allowed for these unique situations.

Based on these items, API offers the following suggested redlines to §60.5397b(h)(3), which are based on existing regulatory language from NSPS VVa:

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[17] 40 CFR §60.482-9a(e)

[18] 86 FR 63174

(3) *Delay of repair will be allowed:*

(i) *If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel*~~.~~*;*

(ii) *If the necessary replacement part supplies have depleted and supplies had been sufficiently stocked before supplies were depleted, the repair must be completed as soon practicable, but no later than 30 days once the necessary replacement part supplies are available; or*

(iii) *If the necessary repair equipment cannot be brought to the site for reasons, such as lease restrictions for farming or seasons for endangered species, the repair must be completed as soon practicable, but no later than 30 days once repair equipment may be brought to the site.*

2.4 Repair timelines should be consistent for leaks identified using AVO or OGI.

The repair timelines should be the same whether the fugitive emissions at well sites, centralized production facilities, and compressor stations are identified using AVO, OGI, or Method 21 because the necessary repair actions are agnostic to the detection method. In other words, operators should have the same time to make repairs regardless of leak detection method because the repair actions depend more on the leaking component rather than detection method.

EPA's stated reason for requiring shorter repair timelines is *"so that the monthly AVO inspections do not overlap the repair schedule"*[19]. This justification is insufficient for two reasons:

- As proposed, monthly AVO inspections would apply only to compressor stations. This overlap would not occur for bimonthly or quarterly AVO inspections at well sites and centralized production facilities.
- EPA has allowed repair timelines to overlap with inspection in other regulations. Under existing LDAR regulations, a component may be on delay of repair for multiple monitoring periods in certain circumstances.

While AVO is generally more effective at detecting larger emissions, the existing OGI repair timelines do not consider emission rate because OGI cannot quantify the leak rate. The same inability to quantify fugitive emissions also applies to AVO, and so EPA should have the same repair timelines for both detection methods. Finally, consistent timelines would also streamline compliance.

To address this concern, API offers the following suggested redline of §60.5397b(h):

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[19] 87 FR 74737

Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made ~~in accordance with paragraphs (h)(1)(i) and (ii) of this section.~~

~~(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using visual, audible, or olfactory inspection.~~

~~(ii) If you are complying with paragraph (g)(1)(i) through (iv) of this section, a first attempt at repair shall be made~~ no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than ~~15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and~~ 30 calendar days after the first attempt at repair ~~as required in paragraph (h)(1)(ii) of this section.~~

2.5 EPA should clarify depressurized equipment are exempt from fugitive emissions monitoring.

State rules, including New Mexico[20] and Colorado[21], exempt depressurized equipment[22] from fugitive emissions monitoring because leak surveys are not anticipated to result in emissions reductions at these facilities. Monitoring would resume once the site or equipment is back in service. EPA should provide a clear exclusion for these types of facilities or equipment under both NSPS OOOOb and EG OOOOc. One suggestion would be to model the regulatory language on the existing storage vessel out of service and return service requirements.

See also Comment 13.3.

2.6 Additional clarification is needed for the proposed definition of modification for a centralized production facility.

EPA's proposed definition of modification for the collection of fugitive emissions components at a centralized production facility presents a challenge since the operator of a centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility especially when the operator differs between the centralized production facility and the offsite wells that send production to it. The operator of the centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility since the upstream operator is typically only required to notify the centralized production facility operator when a new well is drilled and starts to send production to the gathering system. The upstream operator may not necessarily identify the specific centralized production facility. EPA may not have anticipated this scenario in proposing the definition of modification for the collection of fugitive emissions components at a centralized production facility.

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[20] 20.2.50.116.C(9) NMAC

[21] https://drive.google.com/file/d/1a3IJ74txUxJ241wgh-ZMRx0Rn7LV3z2V/view

[22] The CO regulations reference depressurized equipment, while the NM regulation references temporarily abandoned wells.

To address this concern, API suggests that the modification criteria for centralized production facilities be limited to "An increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility". This criterion is simple, clear, and aligned with the purpose and definition of a centralized production facility, which is to gather hydrocarbon liquid production into storage vessels. As such, API offers the following suggested redline of §60.5365b(i)(2):

> *For purposes of §60.5397b and §60.5398b, a "modification" to centralized production facility occurs when~~:~~ an increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility.*
>
> ~~*(i) Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;*~~
>
> ~~*(ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or*~~
>
> ~~*(iii) A well site subject to the requirements of §60.5397b or §60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.*~~

We also suggest EPA add clarification to the definition for central production facility that addresses custody transfer.

2.7 EPA's proposed well closure plan requirements present several technical and legal issues.

After reviewing EPA's proposed well closure plan requirements, API has identified the following technical and legal issues:

- **The proposed well closure plan requirements are duplicative with other regulations.** Well closure requirements are within the jurisdiction of State Oil & Gas Commissions and other agencies, not the EPA. Under state law, a well is required to be plugged and abandoned when it has reached the end of its useful life. In all States, operators must provide written notice of plugging and comply with regulatory requirements to plug and abandon the well, including removing equipment, setting downhole plugs, cementing in the casing, capping the well to prevent fluid migration and restoring the surface site. These practices are done to permanently confine oil, gas and water into the strata in which they were originally found. For wells located on federal lands, separate BLM requirements also apply for well closure. Depending on the well location (e.g., located in an area with potash mining), additional requirements may also apply. For some wells, EPA would be adding a fourth set of well closure requirements.

  Therefore, EPA's proposed notifications and well closure plan requirements are duplicative, unnecessary, and increase administrative burden while providing no discernible accompanying environmental benefit when an operator is working to properly close a well. In certain cases when an emergency plugging is required, the proposed notification timelines may be impossible to meet.

- **EPA does not have the technical expertise to review well closure plans.** State Oil & Gas Commissions have the technical knowledge to evaluate well closure plans, because they have the jurisdiction for well closure. Without the technical knowledge, EPA's proposed well closure plan requirements require

significant operator and agency resources but provide no additional environmental benefit. Operators should only be required to maintain records of an approved well closure plan by the state authority with jurisdiction; these records could be provided to EPA upon request.

Under existing State and BLM requirements, well closure plans include detailed information on the well casing, tubing, and rod dimensions, perforation depths, proposed plug materials, depths, tagging, and verification, leak testing for cast iron bridge plug (CIBP), and other required data.

- **EPA does not have authority under CAA § 111 to impose financial assurance requirements.** Part of the proposed well closure plan is a "description of the financial requirements and disclosure of financial assurance to complete closure". This requirement is clearly beyond EPA's authority under the Clean Air Act (CAA). For more details, refer to Comment 12.8.

- **The proposed requirements may create unforeseen liability consequences.** EPA has not clarified how the proposed well closure requirements will transfer with ownership. Under State and BLM rules, chain of title is defined. EPA should not create duplicative requirements that could create potential liability consequences for operators.

- **The notification prior to well closure should be removed. If EPA finalizes the proposed well closure requirements, EPA must clarify when a well closure plan is required to be submitted.** Language at §60.5397b(l) potentially conflicts with §60.5420b(a)(4) in terms of whether a well closure plan needs to be submitted every time that production ceases for more 30 days or only when the operator intends to close the well and stop fugitive emission monitoring. "Cessation of production" is not defined in the proposed regulations. A 30-day period from cessation of production is not indicative of well closure. Operators may have many instances where wells are shut-in for periods of 30 days or more, with complete intent to return the wells to production. A few examples include a facility undergoing maintenance or repair, shut-in for offset fracturing, lack of access to gathering, or wells on cycled production. We request EPA clarify that the well closure plan requirements and notification only when operators intend to permanently close the well and stop fugitive monitoring.

Overall, API recommends that requirements within NSPS OOOOb and EG OOOOc pertaining to well closure be limited to the following:

- **A recordkeeping requirement to maintain records of an approved well closure plan by the local authority with jurisdiction.** This recordkeeping only requirement would avoid unnecessary and duplicative requirements with State Oil and Gas Commissions. The records could be submitted to EPA upon request.

- **A final OGI survey to confirm no detected fugitive emissions after well closure.** EPA could still require a final OGI survey after well closure.

3.0 Alternative Leak Detection Technologies including Periodic Screening and Continuous Monitoring

API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA

to make key adjustments in the final rules to enhance the use of these technologies and to not unintentionally disincentivize development and deployment of these technologies. Making alternative technologies more accessible in these rules can also have synergistic benefits with measurement-informed inventory goals in related rulemaking such as the Inflation Reduction Act's Methane Emissions Reduction Program and EPA's Greenhouse Gas Reporting Program.

These adjustments are described in our comments below, including initial comments on EPA's FEAST modeling. While API is exploring additional modeling analyses, due to the short comment period, any additional modeling analysis may be provided in a subsequent submittal. We welcome the opportunity for future discussions on this important topic with EPA staff.

3.1 Comments Regarding Both Periodic Screening and Continuous Monitoring Technologies

3.1.1 Technologies should be available for use upon finalization of NSPS OOOOb and EG OOOOc.

To facilitate adoption of alternative leak detection technologies, operators need options available beginning with finalization of the proposed rules. EPA's proposed 270-day review timeline means that technologies would likely not be approved until after the first AVO, OGI, or Method 21 inspection, since the initial inspection would be required 90 days after NSPS OOOOb is finalized. This gap may disincentive the use of alternative technologies as operators would already be required to implement the standard fugitive emissions monitoring program with AVO, OGI, and/or Method 21 inspections.

Recognizing that EPA is unable to approve technologies until the rules are finalized, API proposes that alternative technology applications be granted conditional approval if they are submitted within 90 days after the final rule is published in the Federal Register (based on the proposed timelines for the initial AVO, OGI, or Method 21 surveys). This initial conditional approval period would allow for the immediate use of those alternative technologies to achieve initial compliance with NSPS OOOOb. An alternative to initial conditional approval could be extending the deadline for initial monitoring surveys from 90 day to one (1) year in §60.5397b(f) and §60.5398b(b)(2). Time beyond the 270-day conditional approval would be needed for operators to contract with vendors and conduct the initial surveys.

Operators would be able to use the conditionally approved technologies until EPA provides written disapproval to the requestor. Disapproval of a conditionally approved technology should not be considered a deviation for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology. EPA has already proposed the idea of conditional approval for alternative technologies, so this idea could be extended to allow for technologies to be available for initial compliance. EPA could also utilize technologies approved by a state or another country (e.g., Colorado or Canada) as a starting point for initial conditional approval.

In place of or in addition to initial conditional approval, API recommends that EPA prioritize review of initial alternative technology applications (submitted within 90 days after final rule is published in Federal Register) based on the following criteria:

- The technology is already approved for use by a state or another country. Approval by another agency means that the technology has been reviewed previously and is likely to meet EPA's proposed minimum detection threshold of ≤ 30 kg/hr (based on a probability of detection of 90%) as shown in Table 1 and Table 2 to NSPS OOOOb.
- The technology is already used by one or more operators for monitoring under voluntary efforts or regulatory programs. One potential measure could be the number of sites monitored in 2022 using the alternative technology under voluntary efforts or other regulatory programs.

An initial conditional approval period and prioritization of review would allow for quicker adoption of alternative technologies and would also alleviate pressure from EPA to review a potential influx of applications upon rule finalization. Without these measures, EPA could be overwhelmed with applications, and the full 270-day review period would pass before the first technologies would be conditionally approved.

3.1.2 EPA should clarify how the review and conditional approval process will be implemented.

We request EPA provide the following clarifications regarding the application review and conditional approval process for use of alternate technologies:

- EPA should clarify that operators are able to use conditionally approved technologies until EPA provides written disapproval to the applicant.
- EPA needs to consider how to effectively notify operators when a conditionally approved technology is disapproved.
- EPA should also clarify that disapproval of a conditionally approved technology should not affect compliance for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology.

EPA should also elaborate on how deficiencies in an application will affect the proposed review timelines. For the initial 90-day review and final 270-day review, the proposed regulatory language implies that deficiencies in an application will result in disapproval and require the applicant to revise its request and restart this process. As with other application processes, agencies will typically issue requests for additional information with appropriate deadlines so that applicants can resolve deficiencies without restarting the entire application process. Forcing applicants to restart the process for any application deficiency would further delay the approval of alternative technologies for use by operators.

3.1.3 Emissions detected from covers and closed vents systems using alternative technology or while doing required follow-up surveys do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

As discussed in more detail in Comment 5.1 , emissions detected from covers and closed vent systems are not necessarily violations of the "no identifiable emissions" standard since it is a work practice standard rather than a numerical zero emission standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through alternative technology or a required follow-up survey triggers the

obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented. Treating emissions detected from covers and closed vent systems as violations not only fails to acknowledge technical reality contrary to best system of emission reduction (BSER), but it also disincentivizes the use of alternative technology.

3.1.4 While API appreciates EPA providing modeling, EPA's current model overestimates the effectiveness of AVO and OGI.

We appreciate EPA's efforts to create a technology-agnostic, performance-based alternative test method framework supported by an underlying, publicly available FEAST model. In EPA's model, the probability of detection curves for AVO and OGI have 100% probability of detection for leaks above approximately 200 g/hr and 60 g/hr, respectively. While these are useful detection methods in various applications, these characterizations overestimate their effectiveness in certain field conditions and leads to impractical performance standards for the alternative technologies as discussed further in Comment 3.3.1 for periodic screening and Comment 3.4.5 for continuous monitoring.

For example, AVO inspections are less likely to find large leaks if they are located above the person performing the inspection, they occur in areas that the person cannot enter due to safety concerns (e.g., potential for H_2S exposure), or they are located in areas with high noise among other reasons. While 60 g/hr is the current NSPS OOOOa and proposed NSPS OOOOb and EG OOOOc standard for OGI cameras, probability of detection for OGI also depends on the camera operator and field conditions.[23] A more realistic characterization of AVO and OGI detection methods would create a more realistic equivalency model for alternative technologies. Due to the short comment period, we may continue to analyze EPA's assumptions about intermittency of leaks, model plant configurations (i.e., equipment types and component counts), and leak occurrence in subsequent comments.

3.1.5 The alternative technology framework should allow flexibility in conducting leak surveys due to seasonal challenges.

The alternative technology framework should allow for flexibility in conducting AVO/OGI and screening surveys due to seasonal challenges and weather events. Some examples include but are not limited to:

- Snow cover can adversely affect the ability of some alternative technologies to detect methane during part of the year.
- High winds can also prevent aerial-based technologies from being deployed on certain days.
- Weather events such as hurricanes may limit the ability to deploy OGI camera operators to sites for surveys.

The alternative technology framework should allow different technologies to be deployed at appropriate frequencies throughout the year. The deadline for the next survey would be based on the type of site and the last survey conducted. As an example, at single wellhead only site, an operator could conduct AVO inspections for the first two quarters of the year followed by a screening survey at ≤ 2 kg/hr and then another AVO inspection no later than four months after the screening survey, based on EPA's proposed requirements. Flexibility in applying alternate screening technologies should include provisions that use of a different technology than originally

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[23] Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. *Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions*. Environmental Science & Technology 2020 54 (18), 11506-11514 DOI: 10.1021/acs.est.0c01285

planned (due to weather or other external factors) constitutes an allowance, not a deviation from an operator's monitoring plan.

3.1.6 Framework for alternative leak detection technologies should allow multiple technologies, including satellite, to be combined. More combinations of technologies should be added to the proposed periodic screening matrices.

Overall, API believes that allowing the use of a combination of alternative leak detection technologies can be effective to find and fix leaks. This alternative approach recognizes that each leak detection technology (AVO, OGI, Method 21, periodic screening, or continuous monitoring) has strengths and weaknesses in terms of detection threshold, proximity to the source, localization performance, deployment frequency, and costs. For example, ground-based OGI has a low detection threshold and localizes the leak to a particular component but requires proximity to the source and is infeasible to deploy at higher frequencies. Whereas satellites, aerial and continuous technologies can be deployed more frequently than ground-based OGI, the increased distance from the source may not detect leaks on the component level. With these remote detection technologies, resources can be deployed more efficiently to repair leaks – operators would only need to visit sites with detected emissions to make repairs whereas using only OGI surveys require operators to visit each site but could result in no detected emissions. A continuous monitoring system can quickly detect a leak and depending on sensor location, provide an approximate location, but may not fully visualize its location like a plume map from a satellite or aerial survey. In other words, no individual leak detection technology offers a perfect solution.

By allowing the option for a combination of these various technologies into a single monitoring plan or framework, the weaknesses of one technology can be offset by the strengths of another, and the selected technologies work together to improve leak detection and reduce emissions in a flexible and cost-effective manner. Technologies can be combined such that larger emissions are quickly detected, and technologies that detect smaller emissions are deployed less frequently. Finding and fixing the biggest leaks quickly can greatly impact the overall emission reductions.

A multi-layered approach for leak detection combines various technologies to achieve greater emission reductions. Some fugitive emissions may be detected with traditional OGI or AVO during regular LDAR inspections. Intermittent emissions are not always detected during OGI or AVO inspections; however, they may be detected by a continuous monitoring system. Deploying continuous monitors is not an option for all sites, such as those without access to reliable grid power. Alternatively, an aerial survey may detect emissions from such sites over a large area. Although satellites cannot always detect emissions at the component level, they can be useful for basin-wide detection of large emissions that may occur outside of scheduled inspections. This concept of layering various leak detection technologies is illustrated in the graphic below where lines and layers represent strengths of a given technology while the dashed circles represent weaknesses allowing undetected emissions. An example of this multi-layered approach using data from the Permian Basin can be found in an industry pre-publication paper[24].

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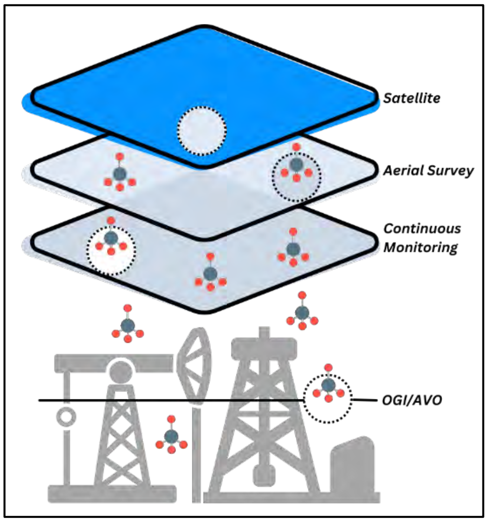
[24] Cardoso-Saldaña FJ. *Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities*. ChemRxiv. Cambridge: Cambridge Open Engage; 2022; This content is a preprint and has not been peer-reviewed. DOI: 10.26434/chemrxiv-2022-f7dfv

Figure 1. Multi-layered Approach for Leak Detection



EPA has already included the idea of layering technologies with the screening survey plus annual OGI survey options in the periodic screening matrices. API has two specific suggestions regarding an alternative multi-layered approach for leak detection:

- **API recommends that continuous monitoring (see also Comment 3.4.1) and satellite technology be included as options directly in the matrices in combination with the periodic survey with and without annual OGI.** In other words, combinations like "Quarterly + Weekly Satellite + Annual OGI", "Quarterly + Weekly Satellite", "Quarterly + Continuous + Annual OGI", and "Quarterly + Continuous" should be modeled and added to the periodic screening matrices with appropriate detection thresholds for the screening technology. Satellite technology would be defined with a ≤ 100 kg/hr detection threshold and a weekly frequency. Having frequent satellite surveys will allow reducing the number of periodic surveys per year for a given detection threshold with and without an annual OGI survey.

- **Separately, we would also welcome an additional optional and flexible framework independent from the periodic screening matrices and case-by-case AMEL process where an operator can develop a monitoring plan for each basin/site with their chosen suite of EPA-approved technologies via EPA-approved modeling.** Similar to EPA's proposed clearinghouse approach to approving alternative screening technologies, EPA could evaluate and approve different modeling platforms for use in developing monitoring plans. Modeling could be refined over time based on data generated through the monitoring plan. The initial modeling should represent the highest emissions level since emissions should decrease over time as NSPS OOOOb and EG OOOOc are implemented over the next several years. This approach would both allow the technology to mature over time and a streamlined approach to alternative modeling compared to the existing case-by-case AMEL process.

  This flexible framework gives operators a clear pathway for a custom, fit-for-purpose option and would be an alternative to both the AVO/OGI requirements and alternative technology requirements. To benefit smaller operators, EPA should consider both a conservative, and realistic, default plan that allows for flexibility in monitoring technology as well as an option where an approved monitoring plan can be used by other operators with similar assets.

3.1.7 Repair timelines should be consistent for leaks using AVO/OGI or alternative leak detection technologies.

Recognizing that repair timelines are part of the overall effectiveness of a leak detection program, API recommends that repair timelines be consistent between traditional (AVO, OGI, or Method 21) and alternative (periodic screening or continuous) leak detection programs. Repair actions depend more on the leaking component rather than detection method. The proposed repair or corrective action timelines in §60.5398b(b)(4) for periodic screening and §60.5398b(c)(6) for continuous monitoring are shorter than those in §60.5397b(h) for fugitive emissions components and §60.5416b(b)(4) for covers and closed vent systems. The shorter repair timelines for alternative leak detection technologies may disincentivize their use. Consistent repair or corrective action timelines would streamline compliance and facilitate the use of multiple technologies. If EPA chooses to finalize shorter repair timelines for alternative technology, API recommends that repairs be prioritized based on higher detected emissions.

3.1.8 EPA should allow operators to use alternative technology to comply with NSPS OOOOa without an AMEL.

Since the proposed NSPS OOOOb fugitive monitoring requirements including alternative technology are at least as stringent as the existing NSPS OOOOa requirements, EPA should allow operators use of alternative technology for NSPS OOOOa compliance without going through the Alternative Means of Emission Limitations (AMEL) process or waiting for state plans to be fully implemented under EG OOOOc. Both the AMEL process and EG OOOOc state plan implementation could take years. EPA can make the NSPS OOOOb alternative technology a compliance alternative for NSPS OOOOa since EPA is planning to update certain aspects of NSPS OOOOa in conjunction with this rulemaking. This addition should not require further notice since the requirements are at least as stringent as the existing NSPS OOOOa requirements. Some alternative technology (e.g., aerial surveys) is deployed over a particular basin or portion thereof and could include both NSPS OOOOa and OOOOb sites. Therefore, allowing the use of alternative technologies for NSPS OOOOa compliance without an AMEL would further incentivize the adoption of these emerging technologies.

3.2 The term “investigative analysis” should replace “root cause analysis”.

The specific term “root cause analysis” has other meanings and specific denotations in various regulations and in the oil and gas industry. There is also a legal issue with how this term can be interpreted in any legal or enforcement proceedings, as well as how it could obligate operators to actions or additional requirements that are not necessarily included within this proposed rule.

API understands and supports EPA’s intent for investigating why certain emission events or leaks have occurred, but recommends the removal of the term “root cause analysis” and replacement with the term “investigative analysis” within NSPS OOOOb and EG OOOOc.

We offer additional comments specific to how “root cause analysis” has been proposed with respect to the super-emitter response program in Comment 1.1.6.

3.3 Comments Specific to Periodic Screening Technology

3.3.1 Proposed periodic screening matrices do not incentivize the use of the alternative technology.

While API acknowledges EPA's proposed matrices of minimum detection thresholds and frequencies, they do not incentivize the use of alternative technology as proposed. To have the same monitoring frequency as OGI, alternative technology must have a minimum detection threshold of ≤ 1 kg/hr for both quarterly OGI and semiannual OGI requirements. This proposed performance level effectively limits the alternative technology options as operators are more likely to use technology with the same or less frequent monitoring than OGI. The proposed performance standards in the matrices are more stringent than needed in part because EPA's FEAST model overestimates the effectiveness of AVO and OGI inspections as mentioned previously in Comment 3.1.4. To incentivize the use of alternative technologies, API believes that quarterly screening surveys with an annual OGI survey should equate to a minimum detection threshold of ≤ 10 kg/hr for sites subject to quarterly OGI; the rest of the matrices would be adjusted accordingly. Supporting modeling analysis may be provided in subsequent comments.

These matrices also do not appear to be based primarily on the minimum leak detection threshold. In proposed Table 1 to Subpart OOOOb of Part 60, the minimum detection threshold is proportional to screening frequency between monthly and bimonthly frequencies without annual OGI (i.e., minimum detection threshold is halved for twice as frequent monitoring). However, if an annual OGI survey is included with monthly and bimonthly screening surveys, the minimum detection threshold is decreased by a factor of 3 instead of the expected 2 (i.e., monthly + annual OGI requires 30 kg/hr detection while bimonthly + annual OGI requires 10 kg/hr instead of the expected 20 kg/hr). While frequency and detection threshold are not the only parts of a leak detection program, one would expect frequency and detection thresholds to be roughly proportional assuming that other aspects of the leak detection program (e.g., repair timelines) are constant.

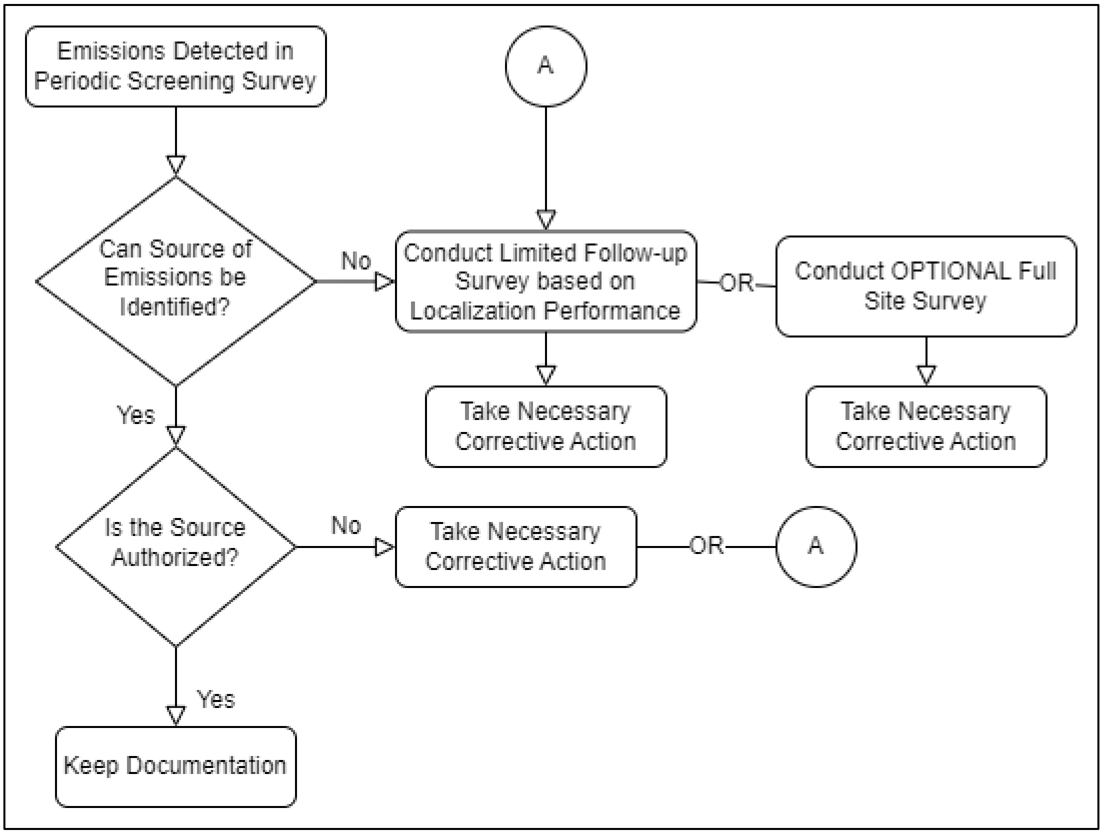
3.3.2 Proposed follow-up actions for periodic screening surveys should be revised.

As discussed in Comment 3.1.7, proposed repair or corrective action requirements for alternative technology should not disincentivize their use. API supports that a full site follow-up OGI survey fulfills the annual OGI survey requirement (where applicable) as indicated in §60.5398b(b)(3)(iii). Regarding the proposed requirements for periodic screening in §60.5398b(b)(4), API offers the following suggestions:

- **The requirements on receiving results of periodic screening and conducting follow-up surveys should be separated from other repair requirements to avoid confusion.** The language in §60.5398b(b)(4) implies that receiving periodic screening results and conducting follow-up surveys are repair requirements when they are both monitoring requirements to detect or confirm leaks.
- **The timeline for receiving results of periodic screening should be extended from 5 calendar days to 5 business days.** Periodic screening surveys can cover hundreds of sites, and so vendors and operators need additional time to process the data for further action.
- **Follow-up surveys and inspections should be limited to sites where the source of emissions cannot be identified based on the localization performance of periodic screening results and other operational information.** Follow-up OGI surveys and cover and closed vent system inspections should not be required if the source of detected emissions can be identified based on the localization performance of the

alternative technology and/or other data. Alternative technology has varying degrees of localization performance in terms of being able to identify emissions on the site-level, equipment group-level, equipment-level, or component-level. Our proposed follow-up action process gives operators the necessary flexibility in responding to detected emissions and is presented in Figure 2and described in detail below.

Figure 2. Flowchart of Proposed Follow-up Actions for Periodic Screening Surveys



When emissions are detected in a periodic screening survey, the operator first tries to identify the source of emissions from the survey results and other available information. For safety and cost reasons, follow-up surveys in the field should be limited to situations where additional information is needed to identify or confirm the source of detected emissions. If the source of detected emissions can be identified, next steps would be based on the type of source.

- If the source of emissions is permitted or otherwise authorized, including maintenance activities, no further action would be required other than to keep documentation. Examples include, but are not limited to, engine or turbine exhaust, uncontrolled storage vessel, planned compressor blowdown, planned engine or turbine startup or shutdown, or properly operating control device. This situation is especially important to compressor stations where periodic surveys are likely to detect emissions from sources operating in compliance with applicable requirements.
- If the source of emissions is a process upset, leak, or other unauthorized release, the operator should be able to directly take necessary corrective actions rather than spending time and effort on a follow-up survey to confirm the source. Taking direct action with the appropriate timelines reduces emissions faster than conducting a follow-up survey first. If the operator determines that a follow-up survey is appropriate to confirm the source of detected emissions, they should be

able to conduct one based on the localization performance of the technology or an optional full site survey.

If the source of detected emissions cannot be identified, operators would conduct a follow-up survey limited to the localization performance of the alternative technology or conduct a full site survey to satisfy the annual OGI survey requirement (if applicable). If two or more full site surveys are conducted within a 12-month period, the most recent full site survey would determine the deadline for the next required annual OGI survey (if applicable). As an example, an alternative technology that can only detect leaks on the site level would require a full site survey while one that can detect leaks down to the equipment would require follow-up surveys only on equipment with detected leaks. Requiring a full site survey anytime that emissions are detected from periodic screening surveys is practically the same monitoring requirement as the primary AVO/OGI requirements but with the additional cost of conducting periodic screening surveys. Due to the large volume of data that can be generated from periodic screening surveys, limited follow-up surveys allow OGI resources to be used in a focused and cost-effective manner. Limited follow-up surveys could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to a full follow-up survey required for every time emissions are detected during a periodic screening survey.

- **Repair timelines should be consistent with AVO/OGI requirements.** Repair timelines should be consistent between traditional and alternative leak detection programs to streamline compliance and facilitate the use of multiple technologies. Therefore, the language in §60.5398b(b)(4)(iii) should simply reference the appropriate repair requirements for fugitive emissions components and covers and closed vent systems.

- **The proposed investigative analysis for control devices in §60.5398b(b)(4)(iv) and covers and closed vent systems in §60.5398b(b)(5) should be initiated within 5 business days.** While API recognizes the importance of proper control device and cover and closed vent system operation, we propose that the investigative analysis be initiated within 5 business days of either receiving the periodic screening survey results in the case that the control device, cover, or closed vent system can be identified as the source of emissions or conducting the limited or full site follow-up survey, whichever is later. This proposed timeline would be consistent with the framework we propose for the SERP in Comment 1.1. EPA's proposed 24-hour timeline is too short to be practical.

- **The proposed investigative analysis for covers and closed vent systems in §60.5398b(b)(5) is more stringent than the repair requirements under §60.5416b(b)(4) and should be removed.** As proposed in §60.5398b(b)(5), a leak or defect in a cover or closed vent system detected by follow-up inspections would require additional analysis beyond repair, including a determination of whether it was operated outside of its design. A leak or defect in a cover or closed vent system detected by routine inspections would be subject only to repair under §60.5416b(b)(4). The investigative analysis for covers and closed vent systems under the alternative technology requirements goes beyond the primary standards, and so §60.5398b(b)(5) should be removed.

- "**Root cause analysis" should be replaced with "investigative analysis".** Consistent with Comment 3.2, the term "investigative analysis" should replace "root cause analysis" in §60.5398b(b)(4)(iv) and §60.5398b(b)(5) (if that requirement remains).

3.4 Comments Specific to Continuous Monitoring Technology

We support EPA's inclusion of continuous monitoring in §60.5398b(c), and our members believe there is great potential in the use of continuous / near-continuous methane monitoring technologies. However, some of the proposed elements are problematic for practical implementation and use of continuous monitors. Therefore, we offer the following comments to craft a more functional continuous monitoring program based on the types of monitors that currently exist, focused on the desired outcome of detecting methane emissions at oil and natural gas production facilities to identify necessary response or repairs, if warranted.

3.4.1 The use of continuous monitoring technology within the periodic screening matrices must be clarified.

The proposed rule language is unclear whether continuous monitoring technology could also be used under the periodic screening survey requirements in §60.5398b(b) and associated matrices. For continuous monitoring technology that simply detects rather than quantifies methane emissions, these technologies could be used for periodic screening surveys. In these situations, the continuous monitor acts like a smoke alarm to notify operators of potential issues. Since continuous monitors can be used more frequently than monthly, EPA should consider adding a more frequent tier or a separate continuous monitoring row to the matrices. The equivalent emission reductions from continuous monitoring could be demonstrated through appropriate modeling. **We recommend incorporating continuous monitoring into the alternative screening matrix for the reasons discussed and to streamline inclusion into the monitoring plan framework we have described in Comment 3.1.6.**

3.4.2 The framework for continuous monitoring should be designed with both fenceline and within-the-fenceline technologies in mind.

As written, EPA's proposed requirements for continuous monitoring appear to be designed for fenceline technology. EPA should clarify that both fenceline and within-the-fenceline technologies can be used and provide details on how implementation would differ between them. API fully expects continuous monitoring technology for methane detection to come within the fenceline and get closer and closer to the source, unlocking emissions reduction potential that is unlikely to be realized by sensors installed on the perimeter. These within-the fenceline technologies will not have many of the limitations of today's fenceline solutions – including no need for wind or meteorological data because these sensors will be in closer proximity to equipment. Limiting the continuous monitoring requirements in this rulemaking to fenceline only would potentially reduce incentives to develop more advanced technology.

3.4.3 Currently available continuous / near-continuous monitoring technology detect methane emissions. The requirement for quantification should be amended.

Current continuous or near-continuous monitors are used to detect emissions and allow for a real-time response by operators; however, these monitors are not and should not be treated as a continuous emission monitoring system like a more traditional "CEMS". These monitors are "high frequency" monitors and not necessarily "continuous" in a traditional sense. The main focus of the monitors should be in the detection of emissions similar to the current OGI framework where the technology is used to find a leak and an operator can then respond, and if appropriate, to fix the leak.

The proposed framework should not be limited by a technology's ability to quantify emissions as this severely limits the types of monitors that can be used and offers a disincentive for operators to deploy the high frequency monitors currently available for deployment. Many technologies on the market today purport to quantify, but industry experience is that the value and accuracy is driven by the system's ability to act as a smoke alarm, where a certain threshold triggers a response system that notifies operators. There is no continuous monitoring technology today that actually "measures" a rate. The "quantification" capability is not derived from the underlying "smoke alarm" sensor but layering that sensor with wind, meteorological and other plume model / inversion model information / assumptions, which has untenable uncertainty.

Therefore, we believe these types of monitors should be considered as effective as the BSER standard, which is quarterly OGI for many larger well sites, central production facilities, and compressor stations. This proposal would have the technologies follow an approach similar to the matrix for other alternate technologies provided in §60.5398b(b) and Tables 1 and 2 to Subpart OOOOb and not follow the action levels in §60.5398b(c).

3.4.4 Continuous / near-continuous monitors should be evaluated against BSER, which is quarterly OGI.

As mentioned, currently available monitors allow for an alarm and response framework that allows operators the ability to evaluate the alarm and mitigate potential leaks. Due to this, continuous monitoring should be compared against the effectiveness of the technology in allowing response and potential repair of leaks against the BSER requirement of quarterly OGI and not based on the type of "fenceline" type framework that has been proposed. Per §60.5398b(c)(1), EPA has defined continuous monitoring as **"***the ability of a measurement system to determine and record a valid methane mass emissions rate of affected facilities at least once for every twelve-hour block."* This equates to daily scans at the facility, which sets an unrealistically high bar for implementation when compared against BSER that sets the most stringent monitoring at quarterly OGI and monthly AVO. The use of high frequency monitors should be consistent with BSER based on the detection capabilities of the monitors.

3.4.5 If EPA keeps its proposed framework for continuous monitoring, the proposed action levels should be revised.

While API overall recommends that continuous monitoring be incorporated with periodic screening to create a single framework for alternative technology, we have concerns with the proposed action levels if EPA choose to keep its proposed separate framework for continuous monitoring. The proposed action levels are based on EPA's FEAST modeling, which does not accurately characterize the effectiveness of AVO and OGI as discussed in Comment 3.1.4. We see merit in including a framework for future technologies that could detect and more accurately quantify emissions, but the currently proposed thresholds are not reflective of actual operations.

Regarding the proposed action levels in §60.5398b(c)(4), API offers the following suggestions:

- **Action levels should be based on detected emissions above an established baseline.** As proposed, the action levels appear to be based on total site emissions, which includes routine or baseline emissions, rather than emissions above an established baseline. Under continuous monitoring, fugitive emissions from leaks are additive to baseline emissions, but they are not additive under AVO/OGI/Method 21 and periodic screening programs. Action levels based on total site emissions effectively sets a limit on site emissions without considering the size or number of emission sources at a site, which could disincentivize the use of continuous monitoring, especially at larger sites. Also, failure to consider baseline emissions

would not exclude contributions from other nearby sources of methane emissions including but not limited to other sites, farming activities, graywater trucks, human populations, etc. EPA should revise the action levels to be based on emissions above baseline and propose how operators establish those baseline emissions.

- **The rolling 90-day (long-term) action levels should be removed as they have no equivalent in the AVO/OGI/Method 21 or periodic screening requirements.** Both the AVO/OGI/Method 21 and periodic screening programs require action to address emissions detected during the monitoring; in other words, emissions are compared to an established immediate or short-term threshold. Neither program has a long-term emissions threshold for action like the rolling 90-day action levels proposed for continuous monitoring. A long-term action level is at best a lagging indicator of an event and would make the investigative analysis of an exceedance more challenging. EPA has not clarified how operators should treat exceedances of the short-term action level that could also cause an exceedance of the long-term action level; operators resolve the short-term event in a timely fashion but may still exceed the long-term action level without any additional events or leaks. Based on these various reasons, EPA should either incorporate continuous monitoring completely into the screening matrix or remove the long-term action levels from the separate continuous monitoring framework.

- **The rolling 7-day (short-term) and rolling 90-day (if they remain) action levels should be revised.** The proposed action levels are too low and therefore practically disincentivize the use of continuous monitors. Despite being the most frequent detection method (every 12 hours as proposed), the proposed short-term action levels of 15 or 21 kg/hr are both below 30 kg/hr, which is the detection threshold for the most frequent periodic screening technology (monthly). A typical minimum threshold for actionable detection and notification is 20 kg/hr for today's technology. The lower the action level, the higher uncertainty on which source is causing the detection, and the likelihood for monitors to detect permitted or other background emissions. One potential solution is to have the short-term action level based on a fixed level to address smaller sites (e.g., wellhead only sites) or a variable level from baseline emissions (e.g., 200% of baseline emissions) to address larger sites.

  The long-term 1.2 or 1.6 kg/hr action levels may also be below the baseline emissions for many sites, which would be especially problematic if they represent total site emissions. Some operators, therefore, would effectively be unable to adopt continuous monitoring for NSPS OOOOb or EG OOOOc compliance.

3.4.6 We support timely and flexible follow-up actions to address any leaks found and request similar repair timeframes consistent with §60.5397b and §60.5416.

API supports the flexible language proposed in §60.5398b(c)(6) that describes initiating an investigative analysis to determine the primary reason for the emissions detected. We believe an operator can perform this investigation in numerous ways including using site-specific data. Due to the various ways that continuous monitors may be used for emissions detection, different follow-up actions may be appropriate for this technology when compared to AVO, OGI, or Method 21. While we appreciate the flexibility, we offer the following suggestions so that follow-up actions do not disincentivize the use of continuous monitoring as discussed more generally in Comment 3.1.7:

- **The timeline for initiating the investigative analysis should be extended from 5 calendar days to 5 business days.** Similar to periodic screening, additional time is needed for data validation.

- **EPA should clarify that the investigative analysis and corrective actions can be conducted remotely where feasible.** Operators should be able to conduct an initial evaluation of detected emissions based on SCADA or other operational data rather than sending a person to the site. Due to safety and cost concerns, operators typically limit the amount of time in the field. Remote investigative analysis and corrective actions could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to an onsite analysis required for each instance of detected emissions.

- **EPA should also clarify that limited or full site follow-up OGI surveys should be allowed in response to emissions detected by continuous monitoring depending on the localization performance of the continuous monitor(s)**. A limited or full site follow-up OGI survey may be a useful tool in identifying the source of emissions and therefore appropriate corrective actions. API recommends that the proposed follow-up action process for periodic screening surveys based on localization performance also apply to continuous / near continuous monitoring; refer to Comment 3.3.2 and Figure 2 for more details.

- **The timeline for completing the investigative analysis and initial corrective actions should be 30 days, not 5 days as proposed.** Follow-up actions for continuous monitoring should be consistent with repair timelines for OGI inspections.

- **Consistent with our suggestions in Comment 3.2, we suggest all references to “root cause analysis” be amended to “investigative analysis”.**

4.0 Associated Gas Venting from Oil Wells

API recognizes the environmental benefit of eliminating the venting of associated gas from oil wells that do not currently recover gas to a sales line, for injection, or for onsite fuel as its primary use. We disagree with EPA’s approach to the control standards proposed including the level of recordkeeping and reporting as it far exceeds the normal level of compliance assurance typically expected from an NSPS. An initial analysis[25] of the impact of the rule on potential production indicates that if the final rule were to eliminate flaring of associated gas, or is implemented in such a way that the practical effect is to eliminate flaring of associated gas, it could result in a substantial loss to production. Such a restriction or implementation would not be supported by API. Should the final rule either expressly or practically eliminate flaring of associated gas, it could be technically infeasible and not cost effective.

We offer the following suggestions with the belief that it is possible to create a manageable regulatory framework that targets the emissions from associated gas at areas without gas gathering infrastructure, including practical compliance assurance, recordkeeping, and reporting.

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[25] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API's request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

4.1 We support recovering gas to sales, for reinjection, used as onsite fuel, or routing gas to a control device. We do not support the additional certifications against emerging technologies prior to flaring associated gas.

We continue to support how EPA had described the proposed requirements for associated gas from oil wells in their November 2021 preamble description, but we do not support the hierarchy of the compliance options and associated recordkeeping and reporting requirements as proposed and believe the requirements should be technology neutral. Specifically, we support:

- Recovering gas to sales in §60.5377b(a)(1) (see also Comment 4.2).
- The beneficial use of the associated as onsite fuel proposed in §60.5377b(a)(2).
- Reinjection of the recovered gas into the well or injection of the recovered gas into another well for enhanced oil recovery proposed in §60.5377b(a)(4).
- Flaring the gas such that 95% control efficiency is achieved as proposed in §60.5377b(b).
- An annual reporting requirement focused on periods of venting.

We do not support the requirement to make an infeasibility demonstration and safety and technical certification statements in order to use a flare to reduce these emissions[26]; especially at oil wells that are connected to gas gathering infrastructure and only temporarily flare gas when unable to sell the gas (see also Comment 4.2). We also note that EPA even uses controlling associated gas with a control device such as a flare as justification for the storage vessel requirements (87 FR 74793) *"…these sites also may be subject to standards for oil well with associated gas and the compliance burden is shared between those affected facilities to ensure emissions from both storage vessels and oil wells with associated gas are reduced by 95 percent."* This statement is evidence of EPA's clear expectations of the use of flares at oil well facilities that may have associated gas, making the need for these additional demonstrations arbitrary.

While we support the concept of other types of beneficial use proposed in §60.5377b(a)(3), we do not support the list of options proposed in §60.5377b(b)(1) (methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas). Each option listed requires specialized equipment, capital investment, and additional energy to implement the technology that would generate emissions, some of which may be greater than flaring the associated gas directly. Furthermore, the cost-benefit of the proposed hierarchy of requirements has not been adequately justified by the EPA. In fact, EPA has not considered the technical feasibility, costs, or benefits from any of these options in the updated Technical Support Document[27].

4.2 The provisions for associated gas at oil wells that primarily recover associated gas to sales, for injection, or used for onsite fuel must be adequately delineated from associated gas from oil wells that do not have adequate or accessible gas gathering infrastructure.

Specifically, the notion that *"recovering associated gas from the separator and routing the recovered gas into a gas gathering flow line or collection system to a sales line"* constitutes a control option as proposed under

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[26] If retained, the infeasibility demonstration that is a prerequisite to control of associated gas must include consideration of commercial availability of alternatives to pipeline injection and of site economics. Consider, for example, the World Bank's "Zero Routine Flaring by 2030," which seeks "to implement economically viable solutions to eliminate [routine] flaring [of associated gas] as soon as possible."

[27] Supplemental TSD Chapter 6 Associated Gas October 2022 / EPA-HQ-OAR-2021-0317-1578_attachment_7.xlsx

§60.5377b(a)(1) is exceptionally problematic since this explains standard business operations for thousands of wells producing a vital energy resource throughout the country. Including this option within the proposal creates tremendous administrative burden in maintaining the records proposed in §60.5420b(c), without generating environmental benefit as the gas is typically being captured to a sales line already. Selling natural gas is part of our business and this sets a uniquely unjustifiable precedent since operators are in the business to sell as much of the produced gas as possible. In the preamble (87 FR 74779), EPA states *"In addition…a significant addition to the proposed rule is the establishment of requirements for situations when associated gas from an oil well that is primarily either routed to a sales line or used for another beneficial purpose is unable to utilize the gas in that manner due to gathering system or other disruptions."* We agree that these wells should have special requirements for the sporadic, short periods of time that gas cannot be recovered, but the current provisions proposed in §60.5377b(a) do not adequately address associated gas that is typically recovered.

For wells where associated gas from the separator is designed and configured to be recovered, we support simplification of the requirements that focus on the short periods of time when gas is not recovered for sale, injection, or reuse. Specifically, we support flaring the gas by using a permanent or temporary control device[28] that achieves 95% efficiency during periods of time when the associated gas is routed to the control device. In this scenario when a well that is configured to route gas to sales or for reinjection can no longer recover the gas for its primary use, the gas should be immediately routed to the flare as soon as practicable. Since EPA has already acknowledged in the preamble (87 FR 74780) that these situations do occur and are outside the control of the well operator, we do not support making technical or safety demonstrations where disruptions or interruptions in the gas gathering infrastructure result in the need to route the associated gas to a control device for temporary periods. For wells that primarily recover gas for reinjection, conducting compressor maintenance may necessitate temporary periods of flaring. This is reasonable given that a facility is designed with a certain configuration for handling the disposition of associated gas and it is unreasonable to expect facilities to design for multiple uses based on emerging technologies before they can resort to flaring; especially during these short intermittent periods.

Any retention of technical demonstrations, for wells that do not primarily recover associated gas, should include economic viability.

4.3 EPA should include a definition for associated gas.

EPA did not include a defintion of associated gas within §60.5430b or §60.5430c, which we do not believe was EPA's intent. Within the preamble[29] EPA uses the following language when describing associated gas. We believe this language with a few additional clarifications would be appropriate to clearly describe associated gas from oil wells for the purposes of NSPS OOOOb and EG OOOOc. The distinctions we provide explicitly determine which separator the requirements proposed in §60.5377b(a) would apply, providing clear transparency for the regulated community.[30]

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[28] A temporary control may be needed in certain situations that an operator may not have planned for or may not have expected. . Allowing both permanent or temporary flare provides flexibility for locations where an existing permanent control device cannot be used or where has not yet been installed.

[29] 87 FR 74778

[30] Without a clear definition, there is uncertainty of what gas EPA seeks to control. For example, some members debate if EPA meant to include flaring from storage vessels. By limiting to the first stage of separation, operators will clearly know what associated gas is applicable.

> *Associated gas means the natural gas which originates at oil wells operated primarily for oil production and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon during the initial stage of separation after the wellhead.*

4.4 Using associated gas as purge or pilot gas for a control device should be considered beneficial use.

Pilot and/or purge gas allow flares and other control devices to operate safely and effectively to reduce emissions. Furthermore, NSPS OOOOb and EG OOOOc require flares and enclosed combustion devices to have a continuously burning pilot flame when the flare is in use. Enclosed combustion devices are also required to maintain a minimum inlet flow rate, which may require supplemental fuel. In other words, pilot and purge gas are part of the fuel requirements for a flare or enclosed combustion device and are not controlled vent streams.

Since the use of associated gas as an onsite fuel source is one of the proposed beneficial use options in §60.5377b(a)(2), we request that EPA clarify that purge or pilot gas for a control device is considered part of onsite fuel use as shown in the following suggested edit to §60.5377b(a)(2):

> *Recover the associated gas from the separator and use the recovered gas as an onsite fuel source, which may include using the recovered associated gas as purge or pilot gas for a control device or flare.*

As an alternative, EPA could clarify that purge or pilot gas for a control device is considered a useful purpose option under §60.5377b(a)(3).

4.5 Special considerations for handling associated gas from wildcat and delineation wells

In our January 31, 2022 comment letter, we asked EPA to allow certain provisions for wildcat or delineation wells in its proposal with respect to the associated gas from oil well provisions. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. In many instances an operator will not know or understand the composition of the gas until after the well is drilled. EPA has acknowledged this fact within the definitions that have been published in §60.5430a and maintained in the proposed §60.5430b & §60.5430c where the terms are defined as:

> *Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.*
>
> *Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.*

In response to our January 31, 2022 comment letter, EPA stated (see 87 FR 74780):

> *"The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for these situations due to lack of specific sufficient information. Therefore, the EPA is interested in additional information on gas compositions of associated gas that would make it both unusable for a beneficial purpose and unable to be flared. The EPA is not only interested in why commenters feel these situations warrant an exemption from the associated gas standards as proposed, but also*

> *what methods are currently in use, or could be used, to minimize methane and VOC emissions in these situations."*

Like provisions within NSPS OOOOa for well completions, EPA should allow special considerations for handling associated gas since these activities are exploratory in nature and are typically not located near existing infrastructure. Wildcat or delineation wells will typically only produce for short period of time after flowback ends in order to complete well testing where the production flow rate is determined along with other parameters such as the gas composition before the well is shut-in or capped, which is regulated based on state protocols.[31] These wells are typically located in remote locations far from any form of permanent infrastructure thereby disallowing any beneficial reuse from a practical and logistical standpoint since the gas composition is not known.

As an example, on the Alaskan North Slope, ice roads must be built to access locations where exploration activities are taking place because roads do not exist, and there is not access/connection to existing oil and gas infrastructure. As we described above, characteristics of associated gas from these wildcat / delineation wells is unknown and therefore it is not wise to use as an onsite fuel source. Currently under NSPS OOOOa and under proposed NSPS OOOOb, the initial well flowback is subject to the well completion operation requirements, which allow for use of a completion combustion device. After the flowback ends, the well undergoes cleanout and a well test (extended flowback) is conducted to determine reservoir characteristics. There will still be open top tanks and a combustion device present; however, this equipment will only be utilized for a very short duration. The compliance requirements for both the provisions in §60.5377b(a) or §60.5412b do not allow for realistic implementation for such unique and short-term operations which are not permanently producing oil from a well.

Since wildcat or delineation wells will typically cease production in well under 180 days[32], a temporary or portable combustion device similar to those used to control emissions from well completions is appropriate to reduce VOC and methane emissions. We therefore request EPA allow any associated gas produced from wildcat or delineation oil wells be routed to a completion combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways). Due to the temporary nature of these activities, the control device compliance requirements should mimic the requirements of control devices utilized for well completions affected facilities, i.e., operated with a reliable continuous pilot flame and no further compliance requirements.

Suggested Redline for inclusion within §60.5377b:

> *For each wildcat or delineation oil well with associated gas at a well affected facility, capture and direct recovered associated gas from the separator to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

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[31] EPA determined well testing "*conducted immediately after well completion, is considered part of the well completion"* for the purposes of reporting emissions under the Greenhouse Gas Reporting Program (see definition of Well Testing Venting and Flaring in §98.238).

[32] We note the initial performance test for enclosed combustion devices not tested by a manufacturer would not be required until within 180 days after initial startup or start of production. Wildcat or delineation wells typically do not produce for this long to warrant compliance with these provisions. Furthermore, duration of well testing flowbacks from wildcat and delineation wells can be limited to 30 days per other agency regulations/guidance, e.g. BLM's NTL-4A guidance (and proposed Waste Prevention rule) generally limits this activity to 30 days, extension beyond 30 days requires additional approval by the agency.

4.6 EPA's Model Plant Analysis Assumptions

Based on preliminary review of EPA's technical support document that was issued in conjunction of the Supplemental Proposal, the associated gas model plant analysis does not include assumptions reflective of actual proposed requirements.

- In our January 31, 2022 letter, we stated *"a more representative cost for installing a flare suitable to control associated gas would be $100,579, based on the average costs EPA uses for analyzing storage vessel controls."*[33]. We also stated, *"that we did not include the costs from EPA's Workbook 'MP1 Plus Monitors.xlsx' as this would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the proposal. If EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA's cost analysis."* In the Supplemental Proposal EPA has proposed additional parametric monitoring but has not included these costs in the analysis.

- The EPA should consider model facilities that have existing control devices but now need to install the correct flow and other parametric monitoring equipment as this would be a type of model plant scenario not evaluated by the EPA.

- None of the beneficial reuse emerging technologies have been included within the model plant analysis. It is unclear how EPA has justified the inclusion of these technologies related to costs, feasibility or environmental benefit/disbenefit.

- EPA includes no costs associated with the technical demonstrations proposed. There are direct costs associated with the engineering certification process, whether companies support in-house engineers or leverage third parties. In previous API comments we have provided to the EPA, we estimated certifications to be $2,000 - $9,000.[34]

- The EPA seems to bias the data selected for baseline emissions to fit their expectation and not based on actual reported data. In section 6.3.1 of the technical support document[35] EPA states,

> *There were 95 facilities/basins that reported associated gas venting emissions [through GHGRP subpart W data]. For each facility/basin, the number of wells venting is reported, along with the total methane vented from all wells. For each facility/basin, we calculated the average emissions per well. These average well emissions ranged from 0.015 tpy to over 2,400 tpy. Almost 20 percent of the facilities/basins had average well methane emissions less than 0.2 tons per year. Explanations of the specific causes of emissions is not provided in the GHGRP subpart W outputs, but it would be expected that routine venting of associated gas would result in emissions greater than this level. In order to avoid selecting a well associated gas venting level that was unreasonably low, a weighted average well emissions level was calculated, using the total emissions from the facility/basin as the weighting factor. The result is an estimated average*

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[33] EPA-HQ-OAR-2021-0317-0039

[34] EPA-HQ-OAR-2017-0801

[35] EPA-HQ-OAR-2021-0317-1578

> *annual methane emissions level of 344 tpy. Applying the representative composition yields a representative VOC emissions level of 96 tpy.*

Within these statements, EPA acknowledges that there are very low methane emissions generated from wells that only temporary flare associated gas when the primary recovery method is not available (i.e. routing to sale, for injection, or used as onsite fuel). However, the EPA in this proposal has not made the distinction between facilities that temporarily flare versus those that are truly stranded.

5.0 Control Devices, Covers and Closed Vent Systems

API supports EPA's decision to maintain the 95% control efficiency standard for control devices within NSPS OOOOb and EG OOOOc, and we acknowledge EPA's desire to assure proper control device performance. The following recommendations will allow this goal to be achieved more effectively at well sites, centralized production facilities, compressor stations, and natural gas processing plants. Specifically, the proposed control device and cover and closed vent system requirements present technical feasibility, timing, and cost issues. To address these concerns, NSPS OOOOb and EG OOOOc should allow for more cost-effective monitoring alternatives and better alignment between monitoring requirements for manufacturer-tested enclosed combustion devices and other enclosed combustion devices. Comments concerning both control devices and closed vent systems are presented in this section.

5.1 Emissions detected from covers and closed vents system do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

EPA states in the Preamble that when a leak is detected in a cover or a closed vent system during a fugitive emissions survey, alternative screening survey, or by a continuous monitoring system, "*the emissions would be considered a violation of the [no identifiable emissions] standard and thus a deviation*"[36]. The "no identifiable emissions standard" or NIE standard is a design and work practice standard (***emphasis added***).

> *You must **design and operate** the closed vent system with no identifiable emissions as demonstrated by §60.5416b(a) or (b), as applicable.37*

As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. EPA has presented no reason in the Proposal to depart from its historical approach regarding fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in

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[36] 87 FR 74804

[37] §60.5411b(a)(3)

compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed.

A “no identifiable emissions” or “no detectable emissions” standard cannot constitute a numerical emissions limitation since BSER must be achievable, so the standard must be applied as a work-practice standard. Even the most well-designed and operated system will develop a leak due to wear and tear on equipment. A zero emissions standard for cover and closed vent system components is practically unachievable because some leaks will happen in the normal course of operations (e.g., typical fugitive leaks) and some develop due to causes beyond an operator’s control. Consider that if a leak from a rusty bolt on a pipe flange is only subject to the standard LDAR work practice standard, then a leak from a rusty bolt on a cover or closed vent system should also only be subject to the standard work practice standard. There is no reason why a typical fugitive leak should be treated differently simply because it occurs on a cover or closed vent system.

Additionally, a leak may develop due to malfunctions or a foreign object (e.g., sand or dust), both of which are not reasonably within the control of the operator. Such leaks are not caused by inadequate design or improper operation and cannot constitute a violation of the “no identifiable emissions” standard. API recognizes the possibility of improperly operating a cover or closed vent system (e.g., forgetting to close a thief hatch), but EPA should clearly differentiate these types of leaks from those described above. For these reasons, EPA’s application of the standard as a numerical emission limitation is not only unachievable but will also have will have a chilling effect on companies that aim to do voluntary leak surveillance, and disincentivize the use of more sensitive instruments. EPA should encourage and incentivize operators to conduct additional voluntary monitoring without the fear of an automatic violation if a leak is detected from a cover or closed vent system.

Lastly, CAA § 111(h)(2) provides that a work practice standard should be prescribed in lieu of a standard of performance (i.e., numeric emissions limitation) when “a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant.” That is precisely the case with EPA’s proposed NIE standards. The NIE standards do not apply to emissions from the storage vessel or equipment to which the closed vent system is installed. Rather, the proposed NIE standard applies to the closed vent system itself. In this case, it is obvious that there is no “conveyance” through which the regulated pollutants would be emitted or captured. To accomplish such an outcome, the closed vent system to which the NIE standard applies would have to be enclosed within another closed vent system or similar permanent total enclosure in order for the regulated emissions to be captured for subsequent control or venting. Requiring such a system would be inordinately costly, highly impracticable, and likely impossible. This is precisely why LDAR standards have been expressed from the inception of such programs almost exclusively as work practice standards. In short, the NIE standard cannot be effectively construed as a zero-emissions standard, as EPA proposes, because no “conveyance” exists that allows for capture of the regulated emissions and application of such a standard to an emissions point.

5.2 Supply chain delays for acquiring flow meters or other monitoring equipment necessitates the initial compliance period must be extended to at least one (1) year after publication in the Federal Register.

Due to EPA’s proposed designation of the applicability date aligned to the November 2021 proposal (see Comment 12.1), operators may not have the adequate flow and net heating value monitoring technology in place for all sites subject to the provisions proposed in NSPS OOOOb, because these additional monitoring requirements were only contemplated but not specifically proposed in that initial proposal. Since EPA’s proposal for consistent control device monitoring requirements regardless of the affected facility will apply to both NSPS

OOOOb and EG OOOOc, the number of control devices subject to monitoring requirements will increase significantly. The current supply chain delay for acquiring flow meters or similar monitoring equipment is currently approximately 6 to 8 months. This delay within the supply chain is expected to be exacerbated based on both NSPS OOOOb and EG OOOOc implementation over the coming years.

In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk.Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap.

As an alternative, a site shutdown to install control device monitoring equipment will result in emissions from the shutdown and purging of equipment and piping. Shutdowns at midstream compressor stations or gas plants could result in gas venting, gas flaring, or a shut-in at upstream facilities. A shorter compliance period will multiply these disruptions as operators work to comply with NSPS OOOOb.

In the 2012 NSPS rule[38], EPA allowed implementation for storage vessel requirements to be phased-in to accommodate the vast number of affected facilities and the number of control devices that would be needed to be acquired. Other state rules, such as those in Colorado and New Mexico[39], have allowed for an orderly phase-in period for certain requirements. EPA must consider that a similar compliance schedule is warranted in the proposed NSPS OOOOb and EG OOOOc based on similar constraints and concerns for acquiring the appropriate monitoring equipment that has historically been exempt from control devices for storage vessel affected facilities. The current supply chain delays in acquiring equipment and limited resources to install equipment are expected to be exacerbated by the large number of control devices subject to monitoring under NSPS OOOOb or EG OOOOc.

Based on feedback from members, we request the initial compliance period for control device flow and net heating value monitoring requirements be extended from 60 days after final publication in the Federal Register to at least 1 year after publication in the Federal Register to allow operators time to order and install the necessary meters assuming that the applicability is based on the December 6, 2022 and other our comments concerning reconstruction and modification are addressed. Additional time, at least another year, would be required if the rules are finalized as proposed. Specifically, compliance with the flow and net heating value monitoring requirements at §60.5417b(d)(1)(vii)(A), §60.5417b(d)(1)(viii)(B), and §60.5417b(d)(1)(viii)(D) along with related operational requirements must be extended to allow operators adequate time to procure and install the necessary monitoring equipment where appropriate as various new equipment is installed, or other equipment is modified or reconstructed.

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[38] See EPA's response at 77 FR 49525-49526.

[39] 20.2.50.122.B(3) NMAC and 20.2.50.123.B(1) NMAC

5.3 With the increased number of control devices subject to flow monitoring requirements, the accuracy requirement for flow meters should be ±10% of maximum expected flow.

For manufacturer-tested enclosed combustion devices, EPA is maintaining the current flow monitoring accuracy requirement of ±2% or better[40]. Historically, this requirement only applied to control devices for wet seal centrifugal compressors and was not required for control devices used to reduce emissions for other affected facilities under NSPS OOOO or NSPS OOOOa. Vent gases from centrifugal compressors have relatively stable flow rates while vent gas from storage vessels is intermittent, low pressure, low velocity / flow, and more difficult to measure.

Since EPA is proposing consistent control device monitoring requirements regardless of the affected facility controlled for both NSPS OOOOb and EG OOOOc, the number of control devices subject to flow monitoring requirements will increase significantly under NSPS OOOOb and EG OOOOc.

The ±2% accuracy requirement may not be technically feasible for most commercially available meters nor cost-effective for control devices on every affected facility at well sites, central production facilities, compressor stations, and natural gas processing plants. As mentioned in Comment 5.2, the availability and cost of meters are negatively affected by supply chain constraints and limited resources to install them. API has previously commented[41] on the challenges with flow monitoring at upstream facilities. This level of accuracy is also more stringent than the ±5% accuracy requirement for flare vent gas flow rates at velocities above 1 feet per second under Maximum Achievable Control technology (MACT) standards finalized under 40 CFR 63 SubpartCC (RMACT)[42].

Two types of commercially available flow meters that are commonly used are thermal dispersion meters or ultrasonic meters. Ultrasonic flow meters are the only identifiable meter that can achieve the ±2% accuracy, but this accuracy may decrease under low-flow or low-pressure conditions. While these meters are technically feasible to meet the proposed accuracy requirement, they may not be economically reasonable with an estimated cost of $20,000 to $30,000 each. In EPA's cost analysis for storage vessels controls[43], the cost of a flare with monitoring equipment was estimated but was not used in the subsequent BSER analysis for new or existing sites. Therefore, EPA did not fully consider the cost-effectiveness of the proposed monitoring requirements for control devices. Thermal dispersion flow meters are less expensive but may not meet the accuracy requirement with a typical accuracy of ±5% or better at high flows (accuracy decreases at pressures less than 25 psig). The lower pressure and variable flow rates from certain affected facilities such as storage vessels also make the accuracy requirement difficult to meet. If a control device is used for controlling atmospheric storage tanks only, it will be operating at less than 25 psig and so even a ±5% accuracy may be difficult to achieve; therefore, the flow meter accuracy requirement must consider this likely scenario. In colder conditions, like those experienced in North Dakota and other states, the liquid drop out caused by condensation can also reduce the accuracy of flow meters and make an accuracy of ±2% technically infeasible. Therefore, API proposes that the accuracy for control device inlet flow rate be increased to ±10% of maximum expected flow.

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[40] §60.5417(d)(1)(viii)(A) and §60.5417a(d)(1)(viii)(A)

[41] API's December 4, 2015, comments on the proposed Subpart OOOOa and January 31, 2022, comments on the proposed Subparts OOOOb and OOOOc.

[42] 40 CFR 63 Subpart CC Table 13

[43] EPA-HQ-OAR-2021-0317-0039, "StTanks_Control_Costs_v5.1.xlsx" and "EPA_Flares_Calc_Sheet_MP1plusmonitors.xlsx"

5.4 Flow monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices.

Manufacturer-tested enclosed combustion devices function similarly to other enclosed combustion devices with the only difference being the party responsible for stack testing; therefore, the proposed flow monitoring requirements should be consistent regardless of whether the device is tested by the manufacturer or owner/ operator. In comparing the proposed flow monitoring requirements for manufacturer-tested enclosed combustion devices at §60.5417b(d)(1)(vii)(A) and other enclosed combustion devices at §60.5417b(d)(1)(viii)(D), the following inconsistencies were noted and should be addressed.

- **No accuracy requirement is specified for other enclosed combustion devices.** As discussed above, the accuracy requirement for flow rate monitoring should be ±5% for both manufacturer-tested and other enclosed combustion devices.
- **Manufacturer-tested devices appear to be limited to flow meters while other enclosed combustion devices may use other parameter monitoring systems.** Other parameter monitoring systems combined with engineering calculations should also be an option for flow monitoring on manufacturer-tested devices especially considering the potential challenges in obtaining and installing a flow meter in a timely fashion. Other parameter monitoring systems are also needed in situations where flow monitoring is infeasible (e.g., low flow scenarios). These other parameter monitoring systems would be more stringent than MACT HH, which allows GRI-GLYCalc™ or other process simulation to calculate inlet flow rate for manufacturer-tested control devices[44].
- **Manufacturer-tested devices do not have an option to exempt the device from flow monitoring.** For enclosed combustion devices not tested by the manufacturer, maximum inlet flow rate monitoring is not required if a demonstration can be made using engineering calculations, and minimum inlet flow rate monitoring is not required if a backpressure valve is properly installed and operated. These alternative compliance options for flow rate monitoring should also be available to manufacturer-tested devices.
- **EPA should clarify that a backpressure preventer is a backpressure valve.** Since backpressure preventer is an unclear term, EPA should use the term "backpressure valve" instead.
- **Additional examples of other parameter monitoring systems should be added to the regulatory text.** To clarify and elaborate on the variety of other parameter monitoring systems that could be used in lieu of a flow meter, EPA should consider adding inlet pressure and line size as additional examples in the regulatory text.

Based on these items, API offers the following recommended redline of flow monitoring requirements for manufacturer-tested control devices in §60.5417b(d)(1)(vii)(A):

> *Except as noted in paragraphs (d)(1)(vii)(A)(1) through (4) of this section, ~~T~~the continuous parameter monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ~~±2~~ ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The flow rate at the inlet to the combustion device*

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[44] §63.773(d)(3)(i)(H)(*1*)

must be equal to or greater than the minimum flow rate and equal to or less than the maximum flow rate determined by the manufacturer.

(1) If you can demonstrate, based on the maximum potential pressure of units manifolded to the control device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the control device cannot cause the maximum inlet flow rate determined by the manufacturer to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.

(2) If you install and operate a backpressure valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.

(3) Control devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

(4) Pressure-assisted flares control devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

API also offers the following recommended redline of flow monitoring requirements for control devices not tested by the manufacturer in §60.5417b(d)(1)(viii)(D):

Except as noted in paragraphs (d)(1)(viii)(D)(1) through (4) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustor or flare. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement.

(1) If you can demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustor cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section or the flare tip velocity limit in §60.18 to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.

(2) If you install and operate a backpressure ~~preventer~~ valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.

(3) Flares that are exempt from maximum inlet gas flow monitoring and enclosed combustion devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

(4) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

Given the small size, dispersed nature, and large number of units affected by this rule, these changes would appropriately reduce the burden of compliance while still providing for compliance demonstration and monitoring.

5.5 EPA must provide the minimum inlet flow rate for current manufacturer-tested control devices no later than publication of the final rule so that owners and operators are able to achieve compliance.

In the preamble[45], EPA states that previously tested manufacturer control devices "*would not need to perform new performance tests*" and "*[t]he zero-level at which the combustion control device was tested will be extracted from the previously submitted performance test report and added to the information on the EPA's website*". This minimum flow rate information must be added to the EPA's website[46] no later than publication of the final rule since owners and operators cannot extract the information themselves as the underlying test reports are not currently available on the website. This minimum flow rate information may also not be easily obtained from the manufacturer directly. EPA must provide this minimum flow rate information no later than publication of the final rule so that owners and operators are able to take any necessary action (e.g., purchase of a different control device or operational changes) to achieve compliance. If the minimum flow information is not provided by the publication of the final rule, EPA should consider implementing a longer initial compliance period (see Comment 5.2).

5.6 EPA should allow the use of alternative technologies within the proposed monitoring requirements.

Given the increasing number of control devices subject to proposed monitoring requirements, EPA should allow the use of alternative technologies to meet the monitoring requirements for visible emissions, continuous pilot flame, and minimum net heating value. Well sites, centralized production facilities, and compressors do not have the same utilities and instrumentation resources as refineries, so alternative technologies would provide more cost-effective monitoring of control device performance.

5.6.1 A smoking check should be the primary monitoring method for visible emissions from flares and enclosed combustion devices.

Thousands of flares and enclosed combustion devices will be subject to proposed monthly Method 22 observations and associated recordkeeping. Each of these observations requires 15 minutes and detailed records to document that the observation was conducted according to Method 22. In total, these observations will add up to hundreds to thousands of hours each month and thousands to tens of thousands of hours per year with no added environmental benefit if the device is operating properly. Compliance can more easily be monitored using a monthly smoking check with a record documenting the time of the observation and whether the control device is observed to be smoking. If the device is observed to be smoking, then operator would be able to either 1) assume the device failed the visible emissions requirement and immediately take corrective actions or 2) conduct the 15-minute Method 22 observation to determine whether the device meets the visible emissions requirement. A monthly smoking check could reduce the time required to monitor the device by more than 90%, and this saved

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[45] 87 FR 74796

[46] https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers

time could be used for other tasks with greater environmental benefit (e.g., conducting a required AVO and/or OGI survey while at the site).

5.6.2 Video camera systems should be allowed as an alternative to Method 22.

Since some sites are already equipped with video camera systems, EPA should also allow video cameras as an alternative method to conduct the required monthly smoking check or Method 22 visible emission observations for enclosed combustion devices and flares. Video camera systems are allowed as an alternative to Method 9 observation under Broadly Applicable Approved Alternative Test Method ALT-82[47]. Although these video camera systems have similar supply challenges to other monitoring equipment (see Comment 5.2), they should be an allowed monitoring alternative. To be consistent with the smoking check or Method 22 requirement, the camera would be used to remotely conduct a smoking check and/or 15-minute observation for visible emissions from the control device every month. Owners or operators would keep a record of this remote visible emission observation with similar information required for in-person smoking check or Method 22 observation. Artificial intelligence and machine learning should be allowed to continuously screen the video feed for smoke detection and if smoke is detected, alert the operator that a Method 22 follow-up is required. Making the requirements for video camera systems more stringent than the proposed monthly Method 22 observation would disincentive the use of this alternative. Recordkeeping and reporting of additional video records could pose potential security risks and data storage concerns.

5.6.3 An automatic ignition system with a flame monitoring device should be allowed as an alternative to a continuous pilot flame.

A continuous pilot flame requires propane or other supplemental fuel at sites without fuel gas. For sites with sour gas, a continuous pilot flame requires either using the sour gas as the pilot or bringing in propane or other supplemental fuel to supply the pilot. Burning propane or other supplemental fuel is costly and generates additional emissions when no vent streams are sent to the control device. Similarly, burning sour gas generates additional emissions including SO_2 and potentially uncombusted H_2S. Some state rules, such as New Mexico[48] and Texas[49], allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. Therefore, API proposes that an automatic ignition system with a flame monitoring device be allowed as an alternative to a continuous pilot flame.

5.6.4 The minimum net heating value demonstration should be simplified.

EPA should provide flexibility to operators by simplifying its proposed minimum net heating value demonstration alternative to continuous net heating value monitoring. Both the proposed continuous net heating value monitoring and demonstration alternative seem excessive considering that the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirements. These vent streams consist of mostly hydrocarbons, and the simplest hydrocarbon (methane) has a net heating value of approximately 900 Btu/scf, which is 450%, 300%, or 112% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf depending on the type of control device.

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[47] https://www.epa.gov/sites/default/files/2020-08/documents/alt082.pdf
[48] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(b) NMAC
[49] 30 TAC §106.492(1)(B)

The proposed minimum net heating value demonstration requires continuous monitoring over 10 days or a minimum of 200 hourly samples of inlet gas to the flare or enclosed combustion device. EPA's justification for such an extensive sampling campaign is *"to provide a large sampling set by which to assess the variability of the vent gas sent to the combustion device and to adequately characterize the tails of the distribution."*[50] EPA did not provide additional detail as to why it expects the distribution of vent gas composition to vary enough to potentially be below the required minimum net heating value. Such a large sampling set is unnecessary when the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirement.

Vent streams from oil well with associated gas, centrifugal compressor, and pneumatic controller in Alaska affected facilities are typically comparable to sales gas or natural gas. In AP-42, natural gas is listed as having a gross heating value of 1,020 Btu/scf (Section 1.4) or 1,050 Btu/scf (Appendix A). The "2011 Gas Composition Memorandum"[51] used in EPA's TSD also suggests net heating values well above the required minimum. Gas composition typically does not change unless certain actions occur at the site, such as adding a new well or refracturing an existing well. Even though the gas composition will typically change with new or modified well streams, composition remains well above the required minimum net heating value.

Vent streams from storage vessel affected facilities consist of more large hydrocarbons than sales gas and have a typical net heating value of 2,000 Btu/scf or more, which is 1,000%, 667%, or 250% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf, respectively. The addition of air from an open thief hatch could drop the heating value of tank vapors below the required minimum net heating value, but the proper operation of thief hatches and other openings are already addressed in the proposed cover requirements.

Vent streams from affected facilities that could potentially be below the minimum heating value requirement include compressors in acid gas service or those at Enhanced Oil Recovery (EOR) facilities. Both situations could have high carbon dioxide (CO_2) content which would lower the net heating value, so operators typically add assist gas or another vent stream with sufficient heating value to facilitate proper control device operation. In these limited situations, API proposes that flow monitoring of the assist gas and vent streams should be allowed as an alternative to the continuous monitoring of net heating value in these limited situations.

Since the vent streams from affected facilities are expected to have sufficient heating value, both the proposed continuous net heating value monitoring and demonstration alternative are economically unreasonable. Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000. These monitors may also experience operational issues with entrained liquids in the vent gas stream especially in colder climates and seasons. For the minimum net heating value demonstration alternative, the cost is expected to be $250,000 or more per demonstration. The cost of a vendor-conducted 10-day continuous monitoring campaign is estimated at a minimum of $250,000 to $275,000 while the cost of 200 hourly samples is estimated at a total of $300,000 to $400,000 with an average cost per sample of $1,500 to $2,000 including shipping and analysis.

Since EPA's proposed minimum net heating value demonstration is too onerous and costly, API proposes the following to provide operators the necessary flexibility to comply with net heating value requirements:

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[50] 87 FR 74795

[51] EPA-HQ-OAR-2010-0505-0084

- The 10-day demonstration be simplified to a single sample including the use of an appropriate, representative sample or an initial flare compliance assessment with §60.18 using Method 18 of Appendix A. If a representative sample is used, the operator must document why the sample is characteristic of the vent stream composition. If the sample or §60.18 assessment demonstrates that the net heating value is at least 150% of the applicable minimum value (i.e., net heating value of the sample is at least 300, 450, or 1,200 Btu/scf, as applicable), net heating value monitoring would not be required. After the initial demonstration, continuous compliance would be demonstrated through subsequent samples once every 3 years. If the initial or subsequent sample is below 150% of the applicable minimum net heating value, the operator would be required to conduct more extensive sampling as proposed below or install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- If an initial or subsequent sample does not meet 150% of the minimum net heating value, operators should have the option to conduct a more extensive sampling event with a lower threshold. API proposes that this more extensive demonstration consist of a minimum of 2 hourly samples or 2 hours of continuous monitoring per day for 7 days for a total of 14 samples. The same number of samples is required for a comparable net heating value demonstration under RMACT[52]. Net heating value monitoring would not be required if all 14 hourly averages or samples are above 120% of the applicable minimum net heating value requirement. After the initial 7-day demonstration, continuous compliance would be demonstrated through a grab sample taken once every 3 years. If the initial or subsequent samples are below 120% of the applicable minimum net heating value, the operator would be required to install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- As with the proposed flow monitoring requirements, net heating value monitoring or demonstration alternative should not be required if operators demonstrate that the net heating value is never expected to below the minimum required value using applicable engineering calculations including process simulation software. This alternative would be similar to MACT HH, which allows GRI-GLYCalc™ or other process simulation software to be used to estimate benzene or BTEX emissions from a glycol dehydration unit[53]. Continuous compliance would be demonstrated through a grab sample taken once every 3 years to verify that the minimum net heating value is being met.

5.7 Minimum operating temperature and associated monitoring requirements should be revised.

NSPS OOOOb proposes a minimum operating temperature of 760 °C and temperature monitoring for enclosed combustion devices that demonstrate that combustion temperature is an indicator of performance during initial performance testing. Other enclosed combustion devices (i.e., those for which combustion temperature is not demonstrated to be an indicator of performance) would be subject to net heating value monitoring requirements. Given the increased number of control devices subject to NSPS OOOOb and EG OOOOc, EPA should revise the minimum operating temperature and associated monitoring requirements in the following ways:

- **Allow operators the flexibility to comply with either temperature or net heating value requirements for enclosed combustion devices that demonstrate that combustion temperature is an indicator of**

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[52] §63.670(j)(6)

[53] §63.772(b)(2)(i)

performance. Some enclosed combustion devices, such as thermal oxidizers, are designed with a minimum operating temperature while others are not. Even if a device can demonstrate that temperature is an indicator of performance during testing, maintaining a minimum operating temperature during actual operation may be challenging and require additional supplemental fuel due to the low or intermittent flow of the vent streams. As proposed, a minimum operating temperature with associated monitoring is the only option for enclosed combustion devices that demonstrate combustion temperature is an indicator of performance. For those enclosed combustion devices, operators should be able to comply with net heating value requirements as an alternative.

- **Allow the minimum operating temperature to be established by performance testing.** Rather than a fixed minimum operating temperature, EPA should allow operators the flexibility to comply with a default minimum operating temperature of 760 °C or the value established by the most recent performance testing. The enclosed combustion device may be able to demonstrate compliance at an operating temperature below 760 °C. Also, additional supplemental fuel may be required to keep the device at a minimum operating temperature of 760 °C when it could achieve a 95% control efficiency at a lower temperature. Operators should be allowed to conduct performance testing as needed to establish a new minimum operating temperature.

- **Allow a minimum operating temperature and temperature monitoring for manufacturer-tested devices.** As proposed, the minimum operating temperature and associated monitoring applies only to enclosed combustion devices not tested by the manufacturer. Like operators, manufacturers should be allowed to demonstrate that combustion temperature is an indicator of performance through performance testing and allow temperature monitoring as an option for demonstrating compliance. Operation and monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices like our recommendation on flow monitoring in Comment 5.4.

5.8 Manufacturer-tested enclosed combustion devices should continue to be exempt from periodic performance testing.

Under NSPS OOOO and MACT HH, manufacturer-tested control devices are exempt from periodic performance testing. Under NSPS OOOOa, manufacturer-tested control devices on centrifugal compressors are exempt from periodic performance testing if the device has continuous flow monitoring. NSPS OOOOb proposes that manufacturer-tested control devices be subject to both periodic performance testing and continuous flow monitoring. These requirements appear contrary to both the technical challenges in conducting performance tests in the field reiterated by EPA and the agency's intent stated in the preamble (***emphasis added***)[54],

> *''[w]e believe that testing units that are not configured with a distinct combustion chamber* ***present several technical issues that are more optimally addressed through manufacturer testing****, and once these units are installed at a facility, through* ***periodic inspection and maintenance*** *in accordance with manufacturers' recommendations.*
>
> *[Text omitted for brevity.]*

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[54] 87 FR 74794

> *For these reasons, we believe the manufacturers' test is appropriate for these control devices with* ***ongoing performance ensured by periodic inspection and maintenance****. ["] (76 FR 52785; August 23, 2011).*

Given EPA's previous rationale for manufacturer testing, the monitoring requirements proposed under NSPS OOOOb, and the increased number of control devices subject to these monitoring requirements, API recommends that manufacturer-tested control devices continue to be exempt from periodic performance testing.

5.9 Enclosed combustion devices subject to minimum operating temperature and temperature monitoring should also be exempt from periodic performance testing.

Under MACT HH, combustion devices are exempt from periodic performance testing if the device demonstrates during initial performance testing that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 °C. NSPS OOOO requirements[55] changed this exemption to devices that meet the outlet TOC performance level and that establish a correlation between firebox or combustion chamber temperature and the TOC performance level. NSPS OOOOa[56] adds a temperature monitoring requirement to the NSPS OOOO exemption for control devices on centrifugal compressors.

Like manufacturer-tested devices, NSPS OOOOb proposes to remove this exemption from periodic performance testing. As such, enclosed combustion devices that demonstrate during initial performance testing that combustion zone temperature is an indicator of destruction efficiency are subject to a minimum operating temperature, periodic performance testing, and temperature monitoring. Given the consistent monitoring requirements proposed under NSPS OOOOb and the increased number of control devices subject to these monitoring requirements, API proposes that enclosed combustion devices for which temperature is correlated with destruction efficiency be exempt from periodic performance testing.

To clarify the requested exemptions from periodic performance testing, API offers the following suggested redline of §60.5413b(b)(4)(ii):

> *You must conduct periodic performance tests for all control devices required to conduct initial performance tests, except ~~for a control device whose model is tested under, and meets the criteria of paragraph (d)~~ as specified in paragraphs (b)(4)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(4)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420b(b)(12).*
>
> *(A) A control device whose model is tested under and meets the criteria of paragraph (d) of this section.*
>
> *(B) A combustion control device demonstrating during the performance test under paragraph (b) of this section that combustion zone temperature is an indicator of destruction*

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[55] §60.5413(b)(5)(ii)(B)
[56] §60.5413a(b)(5)(ii)(B)

efficiency and operates at a minimum temperature of 760 °Celsius or the minimum temperature established during the most recent performance test.

5.10 The continuous monitoring option for organic compound concentration in the control device exhaust may not be technically feasible or economically reasonable. This monitoring option is also meaningless without the corresponding outlet concentration performance standard.

As an alternative to continuous flow monitoring and other similar monitoring requirements, EPA has retained the existing option under NSPS OOOO and OOOOa to use a continuous monitor for organic compound monitoring in the control device exhaust. However, such monitoring may not be a technically feasible or economically reasonable alternative to the other continuous monitoring requirements.

Furthermore, this monitoring option does not make sense since the previous TOC outlet concentration performance standard was not proposed for NSPS OOOOb and EG OOOOc. EPA should clarify if the removal of this alternate performance standard was intentional and how operators should handle compliance for existing control devices that are complying with the TOC concentration standard under NSPS OOOO or OOOOa.

5.11 Technical clarifications for proposed control device requirements.

5.11.1 EPA should clarify requirements for regenerative carbon adsorption systems that use a regenerant other than steam.

For some existing regenerative carbon adsorption systems, residue gas or another regenerant is used instead of steam since the sites typically do not have access to a steam system like a chemical plant or refinery. In the natural gas production and processing industry, natural gas (mostly methane) with a set of heat exchange systems is used to regenerate the carbon beds in place of steam. These systems can be used when there is potential to have air enter the system. A carbon bed does not have a direct fire source which can help limit the potential for a fire in the system. The regeneration cycle is infrequent for these systems. While the proposed requirements for regenerative carbon adsorption systems are unchanged from NSPS OOOOa, EG OOOOc will subject existing sources and control devices to methane standards, and API would like to confirm these regeneration cycles would not be part of the control requirements under this rule. Operators should not be forced to change the operation of their existing control device provided they meet the applicable requirements. Forcing sites to switch to steam regenerant may be technically infeasible or economically unreasonable.

5.11.2 EPA should clarify the proposed requirement language around the presence of pilot flames.

The proposed requirements for control device pilot flames use the following three phrases, each of which could suggest a different meaning:

- A **"continuous burning pilot flame"** means a pilot flame is required at all times regardless of whether the site is operating or vent gas is sent to the control device.

- A **"pilot flame present at all times of operation"** could mean either a pilot flame is required at all times the site is operating or only for those times when the control device is operating (i.e., vent gas is sent to the control device)

- **"Pilot flame while emissions are routed to the control device"** means a pilot flame is required only when vent gas is sent to the device (in other words, at all times of control device operation).

A pilot flame should only be required when emissions are routed to the control device since loss of the pilot flame would result in additional emissions only when vent gas is sent to the device. This clarification would allow for the use of automatic ignition systems (see Comment 5.6.3). This clarification would also be consistent with the compliance requirement found at §60.5412b(b)(1):

> *You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*

API offers the following redlines that clarify a pilot flame should be required only when emissions are routed to the control device like some state rules including New Mexico[57]:

> *§60.5412b(a)(1)(vii): You must install and operate a continuous burning pilot flame or automatic ignition system.*
>
> *§60.5412b(a)(3)(iv): You must install and operate a continuous burning pilot flame or automatic ignition system.*
>
> *§60.5413b(e)(2): A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*
>
> *§60.5415b(f)(1)(vii)(A)(1): A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(d)(1)(i): For an enclosed combustion control device that demonstrates during the performance test conducted under §60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You also must comply with the requirements of paragraphs (d)(1)(viii)(D) and (E) of this section, and you must install a monitoring device that continuously (i.e., at least once every five minutes) indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(d)(1)(vii)(B): A monitoring device that continuously, at least once every five minutes, indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.*

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[57] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(c) NMAC

> *§60.5417b(d)(1)(viii)(A): Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times while emissions from affected facilities are routed to the control device. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.*

> *§60.5417b(g)(1): A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in §60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot flame or combustion flame present for any time period while emissions from affected facilities are routed to the control device.*

> *§60.5417b(g)(6)(iii): There is no indication of the presence of a pilot flame or combustion flame for any 5-minute time period while emissions from affected facilities are routed to the control device.*

> *§60.5420b(c)(11)(i)(F)(1): Records that the pilot flame or combustion flame is present at all times~~ of operation~~ while emissions from affected facilities are routed to the control device.*

5.11.3 EPA should clarify which elements of the control device monitoring plan apply to heat sensing monitoring devices that indicate the presence of a pilot flame.

The proposed control device monitoring plan requirement includes the following exemption: "…*Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements of this section.*"[58] However, one of the listed monitoring plan elements uses a thermocouple as an example. This example is confusing since thermocouples could be used as a heat sensing monitoring device for a pilot flame, or as a temperature monitoring device. In the former case, the exemption would apply but not in the latter. EPA should clarify which elements of the monitoring plan apply to heat sensing devices.

Therefore, API recommends the following redline for §60.5417b(c)(2)(ii):

> *Sampling interface ~~(e.g., thermocouple)~~ location such that the monitoring system will provide representative measurements.*

Alternatively, EPA could propose a different example for sampling interface.

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[58] §60.5417b(c)(2)

5.11.4 EPA should clarify that control devices are not considered fugitive emissions components and how to address emissions from control devices detected during fugitive emissions monitoring.

While EPA recognizes that “control devices should not be treated as fugitive emissions components”[59], EPA adds confusion by trying to address emissions “caused by a failure of a control device subject to §60.5413b” under the alternative periodic screening requirements. API believes that this requirement is intended to address improper control device operation such as an unlit flare when vent gas is routed to it and recognizes that alternative periodic screenings can be an effective tool at identifying such issues. However, such emissions are not fugitive emissions and would not necessarily be part of the follow-up ground-based monitoring survey of fugitive emissions components or inspections of the cover and closed vent system. Since control devices are required to meet a 95% control efficiency, they will always have the potential for uncombusted emissions that could be detected by OGI or alternative technology. Unclear or inappropriate requirements related to detected emissions from control devices may be a disincentive for the use of alternative leak detection technologies. Therefore, EPA needs to reconsider how to better address emissions from control devices that could be detected during fugitive monitoring surveys. Refer to Comment 3.3.2 and Comment 3.4.6 for API’s recommendations concerning follow-up action for alternative technologies.

5.12 Idle control devices at a site should be exempt from performance testing and monitoring requirements.

The proposed NSPS OOOOb and EG OOOOc requirements are unclear on whether idle control devices at a site are subject to performance testing and monitoring requirements. Some state rules, such as Colorado, require control devices be installed based on the potential maximum throughput of a site. For a site, the control devices may be installed and operated in series using pressure-activated valves, meaning that vent gas is sent to the first device until it reaches capacity before the excess vent gas is sent to the second device and so on. In actual operation, sites may never achieve the potential maximum throughput and associated emissions rates, so control devices toward the end of the control system are available but always idle. But even if activated, they would not be needed for purposes of complying with NSPS OOOOb or EG OOOOc.

One potential reading of the proposed NSPS OOOOb and EG OOOOc requirements is that such idle control devices are subject to initial and periodic performance testing and monitoring requirements especially if they are manifolded together. Conducting performance tests on idle control devices could increase in emissions since additional gas would need to be sent to the control devices for the purposes of testing or additional temporary piping installed to route vent gas to the idle control device. Furthermore, a failed performance test on an idle control device would force operators to repair, retrofit, or replace the device, increasing compliance costs with no environmental benefit because the idle device is not expected to be required for compliance. EPA recognized the environmental and cost disbenefit of testing idle emission sources in the federal standards for engines found in NSPS JJJJ[60] and MACT ZZZZ[61]. Similarly, installation of monitoring equipment on idle control devices increases costs with no environmental benefit.

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[59] 87 FR 74724
[60] §60.4244(b)
[61] §63.6620(b)

To clarify that idle control devices are exempt from performance testing and monitoring requirements, API offers the following redlines:

> *§60.5400b(a): General standards. You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas / vapor or light liquid service, and connector in gas / vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.*
>
> *§60.5401b(a): General standards. You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.*
>
> *§60.5412b: You must meet the requirements of paragraphs (a) and (b) of this section for each control device ~~used to comply~~ operated for the purpose of complying with the emissions standards for your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.*
>
> *§60.5412b(a): Each control device ~~used to meet~~ operated for the purpose of complying with the emissions reduction standard in §60.5377b(b) for your well affected facility, §60.5380b(a)(1) for your centrifugal compressor affected facility; §60.5395b(a)(2) for your storage vessel affected facility; §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska; or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (a)(3) of this section. As an alternative to paragraphs (a)(1) through (a)(3) of this section, you may install a control device model tested under*

> *§60.5413b(d), which meets the criteria in §60.5413b(d)(11) and which meets the initial and continuous compliance requirements in §60.5413b(e).*
>
> *§60.5412b(b)(1): You must operate each control device ~~used to comply~~ operated for the purpose of complying with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*
>
> *§60.5417b: You must meet the requirements of this section to demonstrate continuous compliance for each control device ~~used to meet~~ operated for the purpose of complying with emission standards for your well, centrifugal compressor, pneumatic controller, storage vessel, and process unit equipment affected facilities.*
>
> *§60.5417b(a): For each control device ~~used to comply~~ operated for the purpose of complying with the emission reduction standard in §60.5377b(b) for well affected facilities, §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section.*

5.13 The monitoring plan for control devices does not need to be site-specific.

EPA is proposing that each control device have a site-specific monitoring plan to address the monitoring system design, data collection, and quality assurance / quality control elements. Operators may install the same control device and associated monitoring system across sites in one or more company-defined areas. Similar to the fugitive monitoring plan requirement, EPA should allow monitoring plans for control devices to be based on a company-defined area or a company-wide plan for a specific make and model of control device. Like the fugitive monitoring techniques, control device monitoring is based on the type of control device and monitoring system rather than the site itself. Requiring practically identical site-specific monitoring plans for the large number of control devices increases the administrative burden for operators with no environmental benefit.

5.14 The first repair attempt timeline for covers and closed vent systems may be impractical for certain locations.

While EPA has retained the existing NSPS OOOOa requirements[62] for a first repair attempt on leaks detected from covers or closed vent systems, the 5-day timeline will apply to significantly more sites under NSPS OOOOb and EG OOOOc than NSPS OOOO and OOOOa. This requirement may be impractical for some sites that have access limitations such as those on leased farmland. While API recognizes the historic importance and priority of repairing leaks on covers and closed vent systems, a longer timeline, such as 15 or 30 days, may be more pragmatic since the number of regulated covers and closed vent systems will increase significantly under NSPS OOOOb and EG OOOOc requirements. A different first repair attempt timeline could have the added benefit of

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[62] §60.5416a(b)(9) and §60.5416a(c)(4)

making repair timelines consistent between fugitive emissions components and covers and closed vent systems, thus streamlining compliance for operators.

6.0 Storage Vessels

API supports EPA’s proposed 6 tpy VOC and 20 tpy methane thresholds for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. We also support EPA’s retention of the current alternate control standard to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC and 14 tpy methane. With some technical clarification concerning location, API agrees with EPA’s proposed definition for a tank battery.

However, API has concerns regarding EPA’s proposed criteria for legally and practicably enforceable limits, the proposed definition of modification, and some of the proposed operational requirements. These items are detailed in the following section.

6.1 EPA’s proposed criteria for legally and practicably enforceable limits have legal implications beyond this rulemaking and pose permitting challenges.

EPA’s proposed requirements for legally and practicably enforceable limits also have legal implications beyond this rulemaking, and these restrictions violate the concept of cooperative federalism. EPA’s proposed revisions are wholly inconsistent with EPA’s reliance on states to administer the Clean Air Act with regard to Title V and PSD. That is, EPA allows states to establish emission limits on sites that keep sites below Title V and PSD permitting thresholds. EPA should continue to defer to states to determine the appropriate level of monitoring, recordkeeping, and reporting requirements to include in permits rather than imposing a list of strict criteria. This has long been an effective approach to reduce recordkeeping burden while reducing potential emissions.

Just as important as the legal implications discussed in Comment 12.10, the proposed criteria for legally and practicably enforceable limits provide no additional benefit and pose several permitting challenges. Existing permits and associated state programs and rules likely do not meet all the required criteria since EPA has historically deferred to the states on the sufficient monitoring, recordkeeping, and reporting requirements to include in the various levels of permits. For example, permits have proposed annual or rolling 12-month limits on emissions and production since the tank PTE thresholds and NSR permitting thresholds are based on annual emissions. EPA should clarify that such annual limits meet the proposed 30-day averaging time for production limits especially since facilities are typically permitted for a worst-case scenario. Another criterion likely not in existing permits is “*periodic reporting that demonstrates continuous compliance*”. Historically, periodic reporting has applied to major sources under Title V and affected facilities regulated under a NSPS or National Emission Standards for Hazardous Air Pollutants (NESHAP), which is a small fraction of the sites that will be regulated under NSPS OOOOb and EG OOOOc. Monitoring, recordkeeping, and reporting requirements in a permit should be tailored to align with the level of authorization with minor sources having less requirements than major sources. For streamlined permitting mechanisms, such as Permits by Rule in Texas, the state agency would have to engage in rulemaking before operators could rely on such permits for determining storage vessel and tank battery PTE. Such rulemaking could take months to years, meaning that operators cannot rely on legally and practicably enforceable limits until those rule updates are finalized and effective.

The second permitting challenge is the methane emissions threshold. For permitting, methane is typically regulated as a greenhouse gas for major sources under the PSD program. States may not be able to permit a methane limit under their minor NSR programs. As such, EPA should clarify that a methane emission limit is not required to be explicitly listed in the permit provided the control device and/or production limits are included that would limit the PTE from a storage vessel or tank battery to less than 20 tpy of methane. Another approach is to allow a VOC limit of less than 6 tpy to serve as a surrogate for the methane emission limit. A potential consequence of requiring an explicit methane emission limit is that existing tanks may have a permit that does not make them an affected facility under NSPS OOOO or NSPS OOOOa but will not be able to obtain an updated permit for the purposes of EG OOOOc applicability.

Assuming operators can obtain permits that meet the proposed legally and practicably enforceable criteria, the permitting effort for the hundreds of thousands of existing storage vessel designated facilities potentially subject to EG OOOOc will take years and be an administrative burden on operators and the state permitting authorities with no environmental benefit. One member has estimated that it will take ten (10) years to obtain updated permits at the current preparation and agency review timelines. This estimated effort will likely take longer as other operators also seek to update permits at the same time. Given the potential enormous re-permitting burden for existing storage vessels/tank batteries, EPA should allow operators to rely on VOC limits as a surrogate for methane in existing permits that have previously been understood to be legally and practicably enforceable.

Overall, EPA’s proposed requirements for legally and practicably enforceable limits have broad legal implications and impose real permitting challenges. The combined effect is contrary to the historical intent under NSPS OOOO and NSPS OOOOa, which is to lessen the administrative burden while still achieving the desired environmental benefits. API believes that improving the clarity of the storage vessel applicability criteria is a worthwhile effort and offers the following redline for §60.5365b(e)(2)(i):

> *For purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit ~~must~~ may include the elements such as those provided in paragraphs (e)(2)(i)(A) through (F) of this section.*

6.2 The proposed requirements for a modification and reconstruction of a tank battery require additional technical clarifications.

EPA’s proposed definitions of reconstruction or modification for a tank battery require several clarifications. First, the proposed definition for reconstruction is internally inconsistent. For a tank battery consisting of more than one storage vessel, reconstruction is based on replacing at least half of the storage vessels based on the assumption that “*the cost of replacing storage vessel components such as thief hatches and pressure relief devices, in comparison to the cost of constructing an entirely new storage vessel affected facility, will not exceed 50 percent of the cost of constructing a comparable new storage vessel affected facility*.”[63] However, for a tank battery consisting of a single storage vessel, the existing provisions of §60.15 apply on the chance that the cost of replacement storage vessel components could be 50% or more of the cost to construction a comparable new storage vessel. Either the cost depreciable components on a storage vessel other than the tank itself could be 50% or more of the cost of a new comparable tank or not. Practically, this inconsistency means that operators would have to track the cost of storage vessel component replacements for single storage vessel tank batteries, but not for multi-vessel tank batteries. For both single and multi-vessel tank batteries, operators should have the option

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[63] 87 FR 74801-74802

to track either storage vessel replacements or all depreciable components. Based on this recommendation, API offers the following redline of §60.5365b(e)(3)(i):

> *"Reconstruction" of a tank battery occurs when the provisions of §60.15 are met for the existing tank battery ~~any of the actions in paragraphs (e)(3)(i)(A) or (B) of this section~~ and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section. As an alternative to the provisions of §60.15, an operator may determine reconstruction has occurred if at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> *~~(A) The provisions of §60.15 are met for the existing tank battery ; as an alternative to the provisions of §60.15, At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or~~*
>
> *~~(B) The provisions of §60.15 are met for the existing tank battery that consists of a single storage vessel.~~*

Secondly, EPA's proposed definition of modification requires clarification. API supports the first two proposed criteria for modification found in §60.5365b(e)(3)(ii)(A) and (B): "*A storage vessel is added to an existing tank battery*" and "*One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases*". Both these changes require capital expenditure on the potential affected facility (i.e., the tank battery) and would increase emissions. However, the proposed criteria in §60.5365b(e)(3)(ii)(C) and (D) regarding increases in liquid throughput are too broad and is inconsistent with §60.14(e)(2). Per 40 CFR 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification. EPA has not fully explained why it is proposing to deviate from the historical legal understanding of modification which requires both an increase in throughput and a capital expenditure on the storage vessel or tank battery. Also, increases in liquid throughput at well sites, central production facilities, and compressor stations are difficult to track as sites typically track liquid throughput using tank gauging rather than flow meters. Due to the historic understanding of modification and practical challenges of tracking liquid throughput, **API believes that §60.5365b(e)(3)(ii)(C) and (D) should be removed from the definition of modification**. [64]

However, if EPA decides to include increases in liquid throughput as a criterion for modification, API offers the following recommendations:

- **The increase in liquid throughput must also be accompanied by a capital expenditure on the tank battery itself.** Actions, such as drilling a new well or fracturing or refracturing an existing well, could increase liquid throughput and require capital expenditure but not necessarily on the tank battery itself.

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[64] Please see Section 11.6 of our comments on the original proposal for overarching legal comments on the proposed modification definitions. We note that EPA appears to have responded in part to these comments by providing that a modification to a tank battery occurs only when specified actions "result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii)" (the PTE-based applicability thresholds for storage vessels). But we note that EPA's proposed PTE criteria apply to an annual PTE and not, as specified in § 60.14, a short-term measure of PTE (such as lb/hr). This is a significant change in how a potential emissions increase should be considered in determining the existence of a modification because the annual PTE basis in practice likely results in a more expansive modification definition because the short term PTE of storage vessels in almost all cases will be much higher than an annual value, which means that more variation in actual short term emissions can be accommodated without triggering a modification than under an annual metric. EPA fails to explain why it has shifted from a short-term to an annual basis for determining emissions increases associated with a change. As a result, we do not have a reasonable opportunity to understand EPA's rationale and to provide meaningful comments.

These actions would not be considered modifications to the tank battery unless there is capital expenditure on the tank battery itself. This recommendation would make NSPS OOOOb consistent with NSPS A.

- **Reference to process unit in §60.5365(e)(ii)(C) should be removed since process unit is defined such that they should not exist at well sites and centralized production facilities.** Process unit is a term specific to natural gas processing plants and does not apply to well sites and centralized production facilities.

- **Well sites and centralized production facilities should also be allowed to compare liquid throughputs to limits in a legally and practicably enforceable permit like compressor stations and natural gas processing plants.** EPA should be consistent and allow well sites and centralized production facilities to compare liquid throughputs to limits in a legally and practicably and enforceable permit since such a permit can be relied upon for the PTE determination for all sites. **In the absence of a legally and practicably enforceable limit, all sites should be allowed to compare liquid throughputs to those used to design the existing cover and closed vent system in operation when a potential modification action occurs.** These recommendations would also make modification criteria consistent for all sites and clearly define what an increase in liquid throughput is.

Based on these recommendations, API offers the following redlines to §60.5365b(e)(3)(ii):

> *"Modification" of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through ~~(D)~~(C) of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> *(A) A storage vessel is added to an existing tank battery;*
>
> *(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; or*
>
> *~~(C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well).~~*
>
> *~~(D)~~(C) ~~For tank batteries at compressor stations or onshore natural gas processing plants,~~ A capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or ~~(D)~~(C) of this section) determination of the potential for VOC or methane emissions; or in the absence of a legally and practicably enforceable permit, a capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or (C) of this section) design of the storage vessel cover(s) and closed vent system.*

6.3 Additional technical clarifications to proposed definitions are warranted to clarify applicability of certain requirements for tank batteries.

Since the proposed requirements for NSPS OOOOb and EG OOOOc will apply for the tank battery, there are additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria. We support EPA's proposed definition for tank battery based on storage vessels that are manifolded together for liquid transfer, but offer a minor clarification on respect to its location as follows:

> *Tank battery means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant if only one storage vessel is present.*

This clarification addresses the situation of a single storage vessel not located at a well site, central production facility, compressor station, or natural gas processing plant (e.g., drip station along a pipeline). These storage vessels typically have low throughput and methane and VOC emissions. In §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii), EPA does not describe how to determine PTE for tank batteries at location other than a well site, centralized production facility, compressor station, or natural gas processing plant. Therefore, API believes that the agency did not intend to regulate these low-emitting tanks with these proposed rules.

6.3.1 The definition of compressor station must be clarified with respect to the storage vessel applicability provisions in §60.5365b(e).

With the introduction of the newly defined central production facility, an additional clarification is needed for when and how to calculate the tank battery PTE at well sites and central production facilities that may have compression versus at a compressor station. The EPA makes this distinction clearly for how to consider the fugitive emission monitoring by referencing §60.5397b in the definition of compressor station. As an example, consider a reciprocating compressor at an oil processing facility. The facility would be a "*tank battery at a well site or centralized production facility*" under §60.5365b(e)(2)(ii) and yet also a "*tank battery located at a compressor station*" as used in §60.5365b(e)(2)(iii).

We therefore request EPA also clarify the storage vessel requirements in a similar way by referencing of §60.5365b(e) in the definition of compressor station as follows:

> *Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of §60.5365b(e) and §60.5397b.*

In terms of the PTE calculations, centralized production facilities should be considered like compressor stations and natural gas process plants because the storage capacity is typically based on "a projected maximum average daily throughput". Therefore, API offers the suggested redlines for §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii).

> *(ii) For each tank battery located at a well site ~~or centralized production facility~~, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided*

in paragraph (e)(5)(iv) of this section. The potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

(iii) For each tank battery located at a centralized production facility, compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station or onshore natural gas processing plant or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.

Another suggested solution is to harmonize the PTE calculation requirements for all sites based on the requirements proposed for compressor stations and gas plants.

6.3.2 A storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant used to alleviate dangerous, or emergency events must be clearly excluded from the definition of storage vessel.

At some facilities, storage vessels may be installed for the sole purpose of providing relief from pressure vessels during emergencies. Previously, these storage vessels would not trigger applicability as a single emergency use vessel was unlikely to exceed 6 tpy VOC threshold under NSPS OOOO or NSPS OOOOa. These tanks now present a challenge with the new applicability threshold proposed in NSPS OOOOb and EG OOOOc for the tank battery. At the state level, emergency use tanks are exempt from control requirements from states and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.[65,66] We request EPA provide an exclusion for emergency use tanks from the definition of storage vessel as follows:

> *Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:*
>
> - *Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180*

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[65] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[66] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

- *Process vessels such as surge control vessels, bottoms receivers or knockout vessels.*
- *Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.*
- *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

6.3.3 EPA should clarify that location is not a restriction on the use of a floating roof tank.

In §60.5395b(b)(2), EPA correctly prohibits the use of a floating roof if the storage vessel or tank battery has flashing emissions. However, EPA also prohibits the use a floating roof at a well site or centralized production facility. Flashing emissions alone, regardless of location, should prohibit the use of a floating roof tank because flashing emissions, not location, could prevent proper operation of a floating roof.

API offers a recommended redline in Comment 6.5.

6.4 The requirement to manifold the vapor space of each storage vessel in the tank battery is overly prescriptive and unnecessary.

As part of the control requirements for storage vessel affected facility, EPA proposes that "*The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery*"[67]. This requirement to manifold the vapor space of each storage vessel in a tank battery is unnecessary and restricts an operator's flexibility in achieving compliance with the required 95% emissions reduction. An operator should be able to install any number of control devices and manifold the vapor space of the storage vessels from one or more tank batteries into one or more closed vent systems so that each control device is properly sized for the expected vent gas flow rate.[68] The requirement to manifold the vapor space of a tank battery may also cause confusion with the proposed definition of tank battery which is based on storage vessels manifolded together for liquid transfer.

API offers a recommended redline in Comment 6.5.

6.5 EPA should provide an exemption from control requirements due to technical infeasibility if the control device or VRU would require supplemental fuel.

With the change in affected facility from a single storage vessel to a tank battery, control devices will be required for a longer time compared to NSPS OOOO and NSPS OOOOa – until the actual uncontrolled emissions from the tank battery (versus each individual storage vessel) are below 4 tpy VOC and 14 tpy of methane. This longer

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[67] §60.5395b(b)(1)(ii)

[68] If not corrected, EPA's failure to consider these obvious and important aspects of its proposed manifolding requirement would render such a requirement arbitrary and capricious. Motor Vehicle Mfrs. Assn. v. State Farm Mut. Automobile Ins. Co., 463 U.S. 29, 43 (1983).

period for the control requirement will increase the likelihood that some control devices or VRUs will require supplemental fuel to be technically feasible. As discussed in Comment 5.6.3 for control device pilot flames, operators may have to bring propane for supplemental fuel for sites without fuel gas or burn additional sour fuel gas. As such, API recommends EPA consider an exemption from control requirements for a tank battery if use of a control device or VRU would be technically infeasible without supplemental fuel for pilot flame or other purposes. Such exemptions currently existing in state regulations for storage vessels and tank batteries including Colorado. Based on the language for the Colorado exemption, API offers the following recommended redlines to the control requirements in §60.5395b(b), which also includes the previous comment:

Control requirements.

(1) Except as required in paragraphs (b)(2) and (b)(3) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through ~~(iv)~~ (iii) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);

~~*(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;*~~

~~(iii)~~(ii) The tank battery must be equipped with ~~a~~ one or more closed vent systems that meet~~s~~ the requirements of §60.5411b(a) and (c); and

~~(iv)~~(iii) The vapors collected in paragraph~~s~~ (b)(1)(ii) ~~and (iii)~~ of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) For storage vessel affected facilities that do not have flashing emissions ~~and that are not located at well sites or centralized production facilities~~, you may use a floating roof to reduce emissions. If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb. You must submit a statement that you are complying with §60.112b(a)(1) or (2) with the initial annual report specified in §60.5420b(b)(1) and (8).

(3) You may apply to the Administrator for an exemption from the control requirements in paragraphs (b)(1) of this section if the use of a control device would be technically infeasible without supplemental fuel. Such request must include documentation demonstrating the infeasibility of the control device.

7.0 Natural Gas-Driven Pneumatic Controllers

Pneumatic controllers play a pivotal role in the safe operations at oil and natural gas facilities – including at well sites, central productions facilities, compressor stations, and processing plants. In our review of the proposed requirements EPA has not adequately addressed some of the major concerns we identified in our January 31, 2022 comment letter.[69] EPA has severely overstated the deployment capabilities for solar installations to power oil and gas infrastructure in support of their proposal, which indicates a continued lack of understanding of how pneumatic controllers (and pneumatic pumps) would be converted to achieve a non-emitting standard.

For NSPS OOOOb, we support the use of non-emitting pneumatic controllers, contingent on clarifications as described herein, for newly constructed, modified or reconstructed well sites, central production facilities, and compressor stations. We also support EPA excluding emergency shutdown devices from these provisions as it allows for safety in case of emergency.

For existing natural gas-driven pneumatic controllers under NSPS OOOOc, we continue to maintain that 1) adequate time and phase-in must be provided to properly account for the magnitude and scale of sites converting to non-emitting controllers and 2) it is most appropriate to focus conversion to non-emitting controllers at facilities with the largest number of controllers (see Comment 7.5). To effectively do this, the use of low continuous bleed or intermittent natural gas-driven pneumatic controllers should be allowed and should be monitored periodically for proper functioning at the frequency specified in §60.5397c. An initial analysis[70] of the potential impact of the rule should it require conversion to non-emitting pneumatic controllers at all existing facilities shows that it could result in the premature shut-in of a significant percentage of existing wells, particularly when considered in context with the proposed monitoring requirements[71]. EPA should allow additional flexibility in this area as we have described to allow states to preserve the remaining useful life of facilities.

7.1 Adequate implementation time must be provided for pneumatic controller and pneumatic pump requirements under both NSPS OOOOb and EG OOOOc.

As we have stated earlier, adequate time is required to implement the proposed control standards as they fundamentally shift how pneumatic controllers and pneumatic pumps have typically been operated. While new surface locations can typically plan for controls during site design, the supply chain delays pose a genuine and significant concern for all aspects of implementing the pneumatic controller requirements. Anecdotal evidence from one operator that is currently conducting retrofits in New Mexico has identified that air compression equipment is in short supply with around 8 months of delays and another operator that has been piloting solar panel instrument air systems is now experiencing delays of 18 to 24 months on previously made orders. While eventually the market will rise to meet this demand, that market correction has not yet been realized and presents very real concerns for our members. Currently there are hundreds of operators attempting to order equipment for thousands of sites. While we are generally supportive of the proposed requirements (with the necessary and specific clarifications that we have requested), the current proposed timeline for compliance is unrealistic due to global circumstances beyond any operator’s ability to control or influence.

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[69] EPA-HQ-OAR-2021-0317-0808

[70] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API’s request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

[71] See Comment 2.0

As anecdotal evidence, our members operating in New Mexico are currently working through retrofits of facilities in compliance with state regulations. Instrument air systems are currently on backorder with a wait time of approximately 8 months. This wait time is expected to be exacerbated when EPA's final rule takes effect. Once equipment is received, only 1-3 facilities can be retrofit per operator per week based on type or size of the facility, weather conditions, etc. This means for any given operator, only approximately 50-150 retrofits can successfully take place in a single year. For operators with thousands of new, modified and existing locations, the current proposed timelines are untenable.

Based on EPA's proposed November 2021 applicability date, there are thousands of sites that may now require retrofit under NSPS OOOOb. Since operators are currently experiencing 6-to-8-month delays in acquiring the necessary control equipment for instrument air system conversions, we suggest EPA amend the requirements to reference "upon receipt of equipment" similar to how certain delay of repair provisions have been framed within other regulations.

For pneumatic controllers and pumps under EG OOOOc, given all of the existing sites in the U.S. and the implementation aspects outlined above, we continue to have serious concerns that 5 years for conducting retrofits of this magnitude would not provide adequate time given current and anticipated supply chain delays. Because of these constraints for EG OOOOc, EPA should consider a longer phase-in period where facilities with the largest number of controllers are retrofit first.

7.2 For NSPS OOOOb and EG OOOOc, EPA should allow the routing of emissions from natural gas-driven controllers to a control device.

We continue to suport the routing of certain controller emissions to a flare or other combustion device. In its analysis, EPA dismisses this option by finding that routing pneumatic controller vent gas to a process is cost-effective and thus BSER; however, EPA's analysis fails to account for the cost-effectiveness of the incremental 5% of methane and VOC emissions reductions achieved when comparing routing to process against routing to a control device, which conservatively assumes a control device will achieve only 95% reduction.[72] In many cases, the actual performance of a control device exceeds 98% control. Instead, EPA's analysis focuses on the cost-effectiveness of no control against 100% control. API requests that EPA include routing to a control device as a compliance standard under NSPS OOOOb and EG OOOOc. If EPA does not adopt routing to a control device as an emissions reduction standard, it must demonstrate as cost-effective the incremental 5% of emissions reductions achieved through routing to a process or converting to instrument air.[73]

As an example, one facility may choose to install an instrument air system to convert most natural gas-driven pneumatic controllers on site, but emissions from certain types of controllers that are associated with the flare system itself (e.g. back pressure valve[74]) could more easily route emissions to the flare header. By EPA not allowing for this site configuration, some operators may need to reconfigure controllers that are currently already

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[72] 87 Fed. Reg. at 74765-66.

[73] As further support for the above, API responds to EPA's request for information regarding whether vapor recovery units (VRU) are ever necessary to route pneumatic controller vent gas to a process. While it is feasible for operators to route pneumatic controller vents to a downstream process that operates at a lower pressure, a VRU is necessary if no such lower-pressure destination exists or is of limited availability. Installation of a VRU is capital intensive, and VRU maintenance is costly and challenging, especially in extreme weather climates. Where downstream process pressure exceeds vent gas pressure, the pneumatic controller vent gas cannot feasibly route to a downstream process without compression. If EPA is unwilling to allow routing of pneumatic controller vent gas to a control device as an emissions reduction standard on the same footing as routing to a process, EPA should allow routing to a control device where routing to a process is infeasible (taking into account technical and economic considerations), and define infeasibility to include scenarios where routing to a process requires a VRU.

[74] Back pressure valves can be routed to the flare when they are in close proximity to the flare header since they only actuate when there is an over pressurization.

routed to a flare or other combustion device. In this scenario, VOC and methane emissions from these routed controllers are already reduced by 95% or more. EPA has provided no basis for not authorizing routing to control as an option.

Adopting this methodology as a compliance standard can be achieved by amending the proposed definition of “self-contained pneumatic device” to include natural gas-driven controllers routed to control devices in that definition (refer also to Comment 7.3). Such a revision is consistent with both New Mexico and Colorado’s regulations – which define non-emitting to include pneumatics routed to combustion.

7.3 Additional technical clarifications are warranted to clarify applicability of certain natural gas-driven pneumatic controller requirements.

While we support inclusion of flexible solutions to reduce emissions from natural gas-driven pneumatic controllers, we have identified critical aspects of the proposed provisions that require technical clarification or simplification as we have outlined herein.

7.3.1 Suggested clarifications to certain proposed definitions related to pneumatic controllers in NSPS OOOOb and EG OOOOc.

There are some additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria as proposed. There are many types of automated instruments that maintain a process condition that are not pneumatic controllers. Many of the proposed definitions must clearly identify pneumatic controllers from these other instruments and be more specific to avoid confusion.

> ***Bleed rate*** *means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a fixed orifice in a pneumatic controller.*
>
> ***Continuous bleed*** *means a natural gas-driven pneumatic controller that is designed with a continuous flow of ~~pneumatic supply~~ natural gas from ~~to~~ a fixed orifice~~ pneumatic controller~~.*
>
> ***Non-natural gas-driven pneumatic controller*** *means an automated process control device that utilizes instrument air or hydraulic fluid as the motive force to change valve position. ~~Instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.~~*
>
> ***Pneumatic controller*** *means an automated instrument that manipulates a valve’s position with pressurized gas to ~~used for~~ maintain~~ing~~ a process condition such as liquid level, pressure, delta-pressure and temperature.*
>
> ***Self-contained pneumatic controller*** *means a natural gas-driven pneumatic controller in which the motive gas is not vented to the atmosphere but captured ~~releases gas~~ into ~~the~~ downstream piping for process use, sales or control such that there are no direct methane or VOC emissions from the controller.~~, resulting in zero methane and VOC emissions~~*

7.3.2 EPA must clarify the pneumatic controller requirements in NSPS OOOOb and EG OOOOc apply after startup of production and to stationary equipment only.

We agree with EPA'a assertion in the preamble where (87 FR 74759) *"The EPA acknowledges that the focus of the BSER analysis has been on stationary sources and pneumatic controllers that are part of the routine operation of oil and natural gas facilities."* The zero-emissions requirements are not justified for short term controller usage related to non-stationary sources.[75] Retrofitting controllers located on temporary equipment requires significant engineering design that has not been adequately evaluated to identify if these options are even possible, nor technically achievable nor practically attainable. Pneumatic controllers located on temporary or portable equipment should be allowed to operate as low-bleed or intermittent as needed for proper functioning of the temporary equipment. Some examples of temporary equipment or activities that should be excluded from the proposed provisions include the following:

- **Temporary Equipment (such as compressors):** Operators may utilize a small injection compressor to assist in ramping up production for new wells that have recently ended flowback. These compressors are typically skid mounted and located on site for as few as 30 days after the startup of production. These compressors contain a handful of pneumatic controllers to assist in proper function on the unit and may sometimes be leased from a third party. Another example is the use of a temporary compressor at a wellsite that is needed in anticipating gathering system high line pressure during new gathering system infrastructure build-out, which may occur for a few months. We ask that EPA exclude any natural gas-driven pneumatic controllers on equipment that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 180 consecutive days. This approach is consistent with language describing applicability of temporary storage vessels under NSPS OOOO, NSPS OOOOa, proposed NSPS OOOOb, and proposed EG OOOOc.

- **Drilling and Completion Activities:** As EPA is aware, drilling and completion activities require specialized temporary use equipment that is often contracted by third-party operators. Any pneumatic controllers associated with drilling and completion equipment should be excluded from the zero-emitting controller requirements, which can be accomplished by clarifying that the requirements for pneumatic controllers are not applicable until after the startup of production like other provisions within the proposed standards.

7.3.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic controllers.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms 'natural gas-driven pneumatic controller' and 'pneumatic controller' interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic controllers. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric controllers at the well site as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(d)(1):

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[75] Exemption of controllers on temporary equipment is consistent with state regulations in New Mexico and Colorado.

> *For the purposes of §60.5390b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more.*

We offer a suggested redline for reconstruction below in Comment 7.3.4.

To be clear, our support for the proposed provision as it relates to modification for natural gas-driven pneumatic controllers is contingent on this and the other clarifications requested throughout Comment 7.3. Absent these clarifications then we maintain our previous position submitted in our January 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) and request EPA streamline applicability across various affected facilities by defining modification for the collection of natural gas-driven pneumatic controllers and pneumatic pumps like how EPA has defined modification for the collection of fugitive components at well sites and compressor stations. For central production facilities, modification should be based on an increase in designed throughput capacity with the addition of a storage vessel at the central production facility as we further elaborate in Comment 2.6.

7.3.4 Under NSPS OOOOb, reconstruction for natural gas-driven pneumatic controllers should not include replacement of a high-bleed natural gas-driven controller with a low-bleed or intermittent controller.

Many of our members have committed to the elimination of all remaining high-bleed controllers that may still be in use at existing locations. As we included in our January 31, 2022 comment based on data submitted to EPA through EPA's Greenhouse Gas Mandatory Reporting Program, data extracted for the 2020 calendar year clearly shows the breakdown of high-bleed natural gas-driven pneumatic controllers is only around 2% of total reported natural gas-driven pneumatic controllers across both the onshore production segment and onshore gathering and boosting segments. This indicates there are not many high-bleed devices left in operation at well sites, central production facilities, and compressor stations based on successful implementation of NSPS OOOO and NSPS OOOOa over the last decade.

Replacement of these last remaining high-bleed controllers with low-bleed or intermittent controllers would equate to an overall reduction in methane and VOC emissions and should not be included in the reconstruction provisions as this could disincentivize short term benefits of this type of replacement. With the implementation of EG OOOOc coinciding with proposed NSPS OOOOb, this clarification will only delay conversion to non-emitting without impacting current investment in equipment upgrades in the near term that provide immediate environmental benefit.

We offer the following suggested redline to §60.5365b(d)(2) to address these concerns and the clarification explained in Comment 7.3.3:

> *§60.5365b(d)(2): For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of existing natural gas-driven pneumatic controllers at the site in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic controllers is replaced. That is, if*

> *an owner or operator meets the definition of reconstruction through the "number of controllers" criterion in (d)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of natural gas-driven pneumatic controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic controller replacement. Replacement of an individual natural gas-driven controller with a continuous bleed rate greater than 6 scfh with either a natural gas-driven controller with a continuous bleed rate less than 6 scfh or with an intermittent vent natural gas-driven pneumatic controller is excluded from this determination.*
>
> *If the owner or operator applies the definition of reconstruction in §60.15(b)(1), reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven pneumatic controllers at the site. The "fixed capital cost of the new pneumatic controllers" includes the fixed capital cost of all natural gas-driven pneumatic controllers which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].*
>
> *If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic controllers that are replaced, the owner or operator must also comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review.*

7.3.5 Additional clarifications are required to the proposed requirements for reconstruction of pneumatic controllers.

In review of the proposed regulatory text provided for §60.5365b(d)(2), the following are elements of the proposed regulatory text require clarification.

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed in §60.5365b(d)(2).** The proposed language in §60.5365b(d)(2)(ii), suggests that reconstructed natural gas-driven pneumatic controllers would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic controllers. We believe it was EPA's intent to

not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 Supplemental Proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 Supplemental Proposal.

7.4 Self-contained natural gas-driven controllers should follow the requirements for fugitive emission monitoring, not those for closed vent systems.

Self-contained natural gas-driven pneumatic controllers are configured to route emissions into the downstream piping, which is simply a hard piece of pipe with connectors or flanges. Given the simplicity and low potential for leaks or defects along the piping, EPA is correct in allowing OGI inspections, but we believe operators should follow the work practice for the fugitive emission monitoring requirements §60.5397b and not the NIE provisions as proposed.[76] EPA should also allow inspection of self-contained pneumatic controllers via the alternative screening techniques program, when applicable.

We also note that as proposed, the self-contained pneumatic controller requirements do not articulate repair or contain delay of repair provisions or timelines and we believe this was not EPA's intent. Given self-contained pneumatic controllers would more commonly occur on pressure control valves, the operator would likely need to shut-in the well or shutdown equipment in order to conduct any sort of repair (if any were found). We therefore request, at a minimum, that repair timelines in §60.5397b(h) and specifically the delay of repair provisions as described in §60.5397b(h)(3) apply to self-contained natural gas-driven pneumatic controllers.

As we mention in Comment 2.4, we encourage EPA to streamline how periodic monitoring in the proposed rules is conducted by following a consistent set of requirements including the frequency, repair schedule, and retention of associated records. This will provide clarity across all affected facilities at a site where monitoring is occurring.

7.5 For EG OOOOc, locations without access to electrical power should have the option to use low continuous bleed or intermittent bleed natural gas-driven pneumatic controllers with proper functioning confirmed through periodic monitoring until modification or reconstruction triggers NSPS OOOOb. At a minimum, EPA must consider an allowance for low production well sites and/or sites with a limited number of natural gas-driven controllers from retrofit within EG OOOOc.

Many existing well sites are low producing wells that could be close to end-of-life of their production cycle and may only contain a limited number of controllers. The complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production versus implementation of the collective costs associated with EG OOOOc. The BLM acknowledged this fact in their proposed Waste Prevention Rule by establishing an exemption of retrofit of pneumatic controllers based on facilities *"producing at least 120 Mcf of gas or 20 barrels of oil per month"* because *"it is unlikely that an*

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[76] Should EPA continue to apply NIE as a numerical standard for self-contained pneumatic controllers, it could disincentivize conversion.

operator of a lease, unit, or CA producing only 120 Mcf of gas or 20 barrels of oil per month could re-direct the entirety of its revenues for 10 months towards paying for upgrading its pneumatic equipment."[77]

In our previous comment letter submitted January 2022, we supported retrofit for facilities with at least 15 controllers at a well site, central production facility, or compressor station. There have not been any drastic changes in actual costs to retrofit facilities or technical feasibility of implementing these types of retrofits in locations that do not have access to grid power. In fact, due to other similar regulations currently being implemented at the state level, the timeline for acquiring the necessary equipment is long due to supply chain limitations, and skilled labor is in short supply and high demand. We maintain our position that at these existing facilities any high-bleed natural gas-driven pneumatic controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company's fugitive emission monitoring program to monitor for proper functioning. The recordkeeping and reporting for these devices should follow requirements associated with fugitives and not have a separate set of requirements as currently proposed for sites in Alaska.

7.5.1 Spacing constraints at existing sites may cause technical infeasibility for converting to non-emitting controllers where grid power is not available.

Existing well site sites, central production facilities or compressor stations may have sizing constraints for the proper placement (due to safety and other permitting constraints) of instrument air control systems. Examples include an instrument air compressor that must sit outside of classified areas, generators, and/or or solar panels.

To retrofit a facility with an instrument air system, an engineer first verifies that adequate power is available and then applies for necessary state level permits, which takes approximately 60 days to acquire (if approved). On federal lands, this type of project would require reopening permits pursuant to National Environmental Policy Act, which is around a 12 to 18 month permitting process. On private lands, an operator may not be able to purchase additional land from the private owner.

During construction, an instrument air header and compressor skid must be added to the facility. The air compressors must sit outside of classified areas and therefore, some older reclaimed facilities may not have adequate space to add necessary equipment for the instrument air system because the air compressor must be placed outside of a safe radius from existing flares and other hydrocarbon-containing equipment (e.g. limitations due to electrical classifications). If accessible grid power is not available, a generator would have to be installed to power the air compressor, which would emit other pollutants.

7.5.2 Case Study Review for Land Required for Solar Retrofits

For existing medium and larger production sites and tank batteries, larger solar installations will be required to transition the sites to the proposed zero-emitting standard. As a case study, multiple sample sites throughout the country were evaluated to determine the space requirement for a solar installation that is equivalent to the energy of an instrument air system requiring 112 kilowatts (kW), which would be needed for large facilities not included in EPA's model plant analysis. Results are presented in Table 1.

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[77] 87 FR 73606

This case study highlights that the land requirement for many sites is likely to be between 0.6 – 1.5 acres. Several key considerations to consider when installing solar panels at existing well sites that hinder the compatibility include:

- Site area footprints have already been agreed to and installing large arrays will require revisiting existing agreements to modify, a time consuming and costly process. Many jurisdictions, including the BLM, prefer smaller facility footprints.
- Site layout is already optimized for existing infrastructure to fit within a facility area.
- Adding in solar infrastructure of panels, wiring, battery, etc. could lead to complications and unnecessary safety hazards as batteries are introduced near hydrocarbons.
- Snowfall is prevalent in many of these regions and will reduce efficiency of the optimally angled panels. Vertically oriented arrays to prevent snowfall interference may not be appropriate in all circumstances unreasonable given the climate, wind, and remote nature of these sites.

Table 1. Case Study – Physical Land Requirement for Solar Installations Replacing Power Supply for 112 kW Generator

Site Location	Optimally Angled Panels[a]					Vertically Angled Panels[b]				
	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage[g]
	kW	degrees	Hours			kW	degrees	Hours		
Carlsbad, New Mexico	620	28	5.1	2,067	0.7	1513	90	2.1	5,044	0.9
Midland, Texas	620	28	5.1	2,067	0.7	1558	90	2.0	5,193	0.9
Arnett, Oklahoma	735	30	4.3	2,452	0.8	1318	90	2.4	4,392	0.8
Denver, Colorado	719	31	4.4	2,396	0.8	1171	90	2.7	3,904	0.7
Pinedale, Wyoming	988	33	3.2	3,294	1.1	1091	90	2.9	3,635	0.6
Williston, North Dakota[h]	1318	35	2.4	4,392	1.5	1091	90	2.9	3,635	0.6

a. Optimally angled tilt (annual average) determined from National Renewable Energy Lab (NREL)'s PVWatts® Calculator; https://pvwatts.nrel.gov/pvwatts.php

b. Vertically angled systems were suggested by Clean Air Task Force at EPA-HQ-OAR-2021-0317-1451.

c. Size of installation determined from Omni calculator methodology required inputs of electricity consumption and solar hours per day to determine roof area of solar panels; https://www.omnicalculator.com/ecology/solar-panel

d. Using NREL's PVWatts calculator in conjunction with the Omni calculator, it was determined roof area was equal to ground area for simplification as, there was a <1% difference in annual kWH production.

e. Footprint Hero was used to determine the lowest monthly average daily peak sun-hours for each location for both panels at optimal angle and 90 degrees; https://footprinthero.com/peak-sun-hours-calculator

f. Number of panels based on average panel output of 300 watts and 15 square feet.

g. Acreage for vertically angled panels assumes panels would be stacked two panels high.

h. The high latitude of Williston, North Dakota has the lowest monthly average daily peak sun-hours when the solar array is optimally positioned. When vertically positioned the peak sun hours increases from 2.4 hours to 2.9 hours.

EPA should also consider the following in conjunction with results of this analysis:

- the cost of land acquisition;

- right-of-way and easement concerns/limitations;
- projection of further land-use change requirements for solar installations; and
- percent of further land use change required for solar installations on designated wetlands.

For existing locations without accessible grid power and where there is an ability to acquire additional land to use solar or natural gas generators, operators will not have the ability comply with the current proposal.

7.5.3 The incremental costs and benefits have not been adequately justified at existing locations.

Within the technical Support documentation, EPA does include a scenario for monitoring intermittent vent controllers. Based on EPA's own assumptions, this type of program can achieve 96.7% reductions in emissions (based on emission factors) for an overall site level control efficiency of 65% based on semi-annual OGI monitoring. Since many large facilities within the proposal will be required to conduct quarterly OGI, we anticipate this control efficiency to be even higher.

Furthermore, since all well sites, central production facilities and compressor stations will already be subject to fugitive emission monitoring at some frequency, the incremental cost to implement such a program for pneumatic controllers would be solely based on the additional recordkeeping and reporting that an operator would need to implement. The incremental costs and benefits associated with the zero-emitting provisions in comparison with this option to monitor controllers for proper functioning within a company's LDAR program, have not been adequately justified given the numerous technical infeasibility challenges communicated with implementing solar-powered electric controllers, spacing constraints at some existing facilities to install certain equipment, and other emission offsets that will stem from implementing other forms of power generation.

In EPA's analysis, the emission reductions from inspections of intermittent vents are based on emission rates assumed to be halfway between perfectly operating post-inspection controllers and the overall emission rate that includes both perfectly operating and malfunctioning controllers. This suggests that EPA has no data or understanding of how often intermittent bleed devices may not function properly, which is an important distinction given the expected costs of implementing these requirements at all locations as proposed under EG OOOOc.

7.6 EPA's cost-benefit analysis significantly underestimates the costs of implementing the proposed zero-emissions standard and overestimates the technical capabilities of solar and electric controllers.

In our January 31, 2022 comment letter, we provided detailed comments on the technical challenges that operators within U.S. are facing as they convert facilities to electricity, pilot solar powered instument air systems, and install natual gas-driven instrument air systems, which we incorporate again by reference.[78] As our members begin to plan, design and install zero-emitting penumatic controllers, it is clear that EPA has not adequately accounted for the costs of this proposal; especially with respct to retrofit of existing facilities. Total project costs, including equipment and labor, to retrofit a large gathering and boosting compressor station could exceed $1,000,000, which is substantially higher than EPA's projections.

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[78] Comments found in EPA-HQ-OAR-2021-0317-0808

Upon review of the supplemental techncial Support Document, we have found EPA's cost-benefit analysis to significantly underestimate the cost (especially for retrofit of existing facilities) and overstate the techncial feasibility of making these retrofits as summarized below:

- EPA applied an emission factor for low-bleed pneumatic controllers, with a factor that by definition would be a high-bleed pneumatic controller. EPA has justified this update within the model plant by aligning the model plant to the proposed changes to Subpart W which is 6.8 scf/h. This emission factor is nearly a five-fold increase to the continuous low-bleed device emission factor; is greater than the threshold that had been applied to determine whether a device should be categorized as low-bleed or high-bleed; and a device with this level of emissions would not be allowed pursuant to NSPS OOOO or NSPS OOOOa. In our review of the proposed changes to Subpart W, we have asked EPA to provide the details of how this factor was determined as there is little documentation supporting this change. Regardless, it is an inappropriate factor for applying to a low-bleed device for NSPS OOOOb and EG OOOOc because an operator would not be able to install a continuous bleed natural gas-driven pneumatic controller with this manufacturer rating as it is considered a high-bleed pneumatic controller.
- EPA continues to describe application of solar-powered and electric controllers as being directly powered by the grid or solar technology in the model plant analysis. Operator experience is that sufficient air is required to properly control the pneumatic controllers, where an instrument air system (i.e., an air compressor and associated equipment and piping) is required in nearly all applications. Electric controllers lack the speed and performance of gas-powered or air-powered actuators and there are limited equipment configurations where electric controllers are technically feasible. Specifically, electric controllers have inadequate duty cycle ratings, and the torque ratings are typically too low for reliable performance. This significantly limits the utility of electrically actuated controllers. Even if they performed comparably to gas-powered actuators, electrically actuated controllers have a higher failure rate, especially for throttle service where the actuator is constantly adjusting based on process conditions instead of at a set point. The modelled analysis for these scenarios incorrectly estimates the cost-effectiveness of the proposed requirements.
- Application of solar technologies as it pertains to gathering and boosting compressor stations have not been adequately reviewed in EPA's model plant analysis. The production sector model plants are geared toward small well sites with only 4, 8 and 20 controllers analyzed. Larger facilities, i.e., those with more than 20 pneumatic controllers, are still not adequately accounted for.
  - The assumptions made by EPA in the model plant analysis severely underestimate the air compressor horsepower and instrument air needs for sites with more than 20 controllers. These smaller scale cost metrics will not linearly scale up with larger facilities where a new instrument air header and piping may need run across the larger Gathering & Booster station site and additional pipe supports or extended pipe rack may be necessary. In our January 31, 2022 comment letter we provided information on facilities using instrument air systems to power over 100 controllers.
- In a case study published by NREL[79], solar panel capital costs for off-grid production well sites are 2.7 times the cost of grid-connected well sites. This does not align with EPA assumptions.
- EPA's model plant assumptions do not adequately address costs associated with retrofit of existing facilities. We note that installation also necessitates the facility be temporarily shut in/shut down to

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[79] https://www.nrel.gov/docs/fy20osti/76778.pdf

perform retrofits, which does not appear to be accounted for. Additional costs for retrofit at existing facilities that are missing from EPA's analysis include:

  - Additional Land Requirement for Solar Panel Installation including acquisition costs.
  - Site Preparation – For existing sites with tree lines, trimming may be required to maximize sun exposure. Additionally, for larger sites with more significant solar installations, foundation prep including concrete slabs was not considered.
  - Solar panel maintenance and cleaning particulate accumulation.
  - Permitting[80], Insurance and inclusion of battery boxes to house batteries in cold regions do not appear to be accounted for.
  - Retrofits often require the existing methane pipe headers to remain in place as a source of fuel gas for on-site equipment (compressors, fired heaters, combustors/TO's, flares, etc.) and a new parallel air header needs to be run to a to all instruments. This can add significant costs depending on the site layout, if there is available space in the existing pipe rack and facility, or if additional pipe supports are also needed.

- While EPA recounts and summarizes the significant number of comments criticizing solar-powered controllers (87 FR 74764), the primary underlying basis to EPA's economic and technical feasibility analysis pertaining to the conversion of existing, natural gas-powered pneumatic control systems to zero-emission systems (e.g., electric, solar-powered) is based on a single report: *Zero Emission Technologies for Pneumatic Controllers in the USA initially published in August 2016 and then updated in November 2021 by Carbon Limits (on behalf of the Clean Air Task Force).*[81] The report and EPA's application of report costs within the model plant analysis have a number of flaws as we have described herein and as follows:

  - The 2021 Carbon Limits report authors primarily gathered information through interviews with three technology providers and two oil and gas companies, both production-oriented companies with limited application of the technologies. The report is based on installation of solar-powered instrument air systems at only 22 onshore production sites located in Alberta, Canada, Wyoming, Utah, and Peru. This is an extremely small sample size for a technology to be deemed technically feasible and cost effective for all U.S.-based oil and natural gas operations. In response to our comments Clean Air Task Force states "Some of the interviewed technology providers have installed these systems in over 400 well-sites." Again, this is a rather small population when considering the number of facilities that will be applicable to these rules.

  - The Carbon Limits report focuses on reliability of solar power systems in colder climates, not areas with limited sun exposure. The Canadian provinces cited in the study, Alberta and British Columbia, experience very large amounts of sunshine, supporting the idea that solar power

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[80] https://www.solarpermitfees.org/SoCalPVFeeReport.pdf

[81] This basis was explicitly stated by EPA on page 46 of 173 to document Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS), 40 CFR Part 60, subpart OOOOc (EG) (October 2022). EPA states, "The EPA notes that the primary basis for the costs used for the November 2021 analysis was not the White Paper, but rather a 2016 report by Carbon Limits, a consulting company with longstanding experience in supporting efficiency measures in the petroleum industry.The analysis was updated to reflect the information in the 2022 Carbon Limits report."

generation works best in areas with more sun. The study does not support reliability of solar powered systems in areas of limited sun exposure like West Virginia.

- Identified calculation errors and assumptions in the model plant analysis:
    - The EPA cost analysis appears to contain a calculation error in determining the annualized project cost; while a solar panel lifespan of 10 years was stated, a value of 15 years was used in the annualization, resulting in a 30% annual cost difference. See tabs in Supplemental TSD Ch 3 Pneumatic Controllers.xlsx tabs *BSER T&S new, BSER T&S existing, BSER Production new, and BSER Production existing.*
    - The EPA capital cost analysis for electric compressor retrofit at existing transmission, storage, and production sites does not consider applications greater than 10 hp (highest compressor and associated equipment (e.g., dryers, wet air receivers) is capped at $32,000). Larger-sized systems should be evaluated.
    - For electric powered compressed air systems, EPA applied an annualization period of 15 years. If the compressor equipment life is updated to reflect the 2021 Carbon Limits Study provided value of 6 years, this option is not economically feasible. It is unclear why EPA deviated from the Carbon Limits study for this assumption and not others.
    - Carbon Limits updated certain assumptions in the 2021 report release. For some assumptions, EPA continues to retain costs from the 2016 study, without explanation.
    - The Carbon Limits report assumed a greenfield installation factor of 1.5 times major equipment costs without any adequate explanation. Member experience suggests this is closer to 3 to4 times equipment costs.
    - EPA continues to assume at least 1 high-bleed pneumatic controller is present at existing source model plants, when the data submitted to EPA pursuant to 40 CFR Part 98, Subpart W suggests this is an incorrect assumption given the low number of high-bleed controllers still being reported. See Attachment C in EPA-HQ-OAR-2021-0317-0808.
    - The EPA deflated costs provided in 2021 dollars to 2019 dollars. As inflation continues to be elevated, this is an unrealistic assumption and not reflective of actual, or anticipated costs. Costs continue to increase across the economy. A more appropriate assumption would be to assume 2021 dollars are equal to 2019 dollars.

7.7 Recordkeeping and Reporting

As more surface site locations electrify pneumatic controllers over time, confirmation of compliance would be easily obtained through any inspection of a site that was connected to grid power, using solar panels or other instrument air system. Based on review of the issued reporting form (EPA-HQ-OAR-2021-0317-1536_content), it appears EPA's intent was to streamline recordkeeping and reporting to only natural gas-driven controllers, which are the affected facility. However, the language proposed within NSPS OOOOb per §60.5420b(c)(6)(i) and EG OOOOc is unclear in this regard. EPA should not require recordkeeping or reporting on pneumatic controllers that are not natural gas-driven.

8.0 Natural Gas-Driven Pneumatic Pumps

8.1 The applicability date for pneumatic pumps under NSPS OOOOb should be the date of the Supplemental Proposal.

While we maintain that the applicability of NSPS OOOOb should apply based on the December 2022 Supplemental Proposal, which included regulatory text for all affected facilities, this is particularly true for natural gas-driven pneumatic pumps. In the preamble (87 FR 74770)[82], EPA even acknowledges the proposed rule varies significantly from what was described in the November 2021 description for pneumatic pumps:

> ***The proposed NSPS OOOOb requirements in this Supplemental Proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition.*** *As noted above, in the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven pneumatic pump. In this Supplemental Proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site.*
>
> ***…****Specifically, the EPA is proposing that pneumatic pumps not driven by natural gas be used.* ***This is a significant change from the November 2021 proposal,*** *which would have required that emissions from pneumatic pump affected facilities be routed to control or to a process, but only if an existing control or process was on site****. (emphasis added)***

In these statements EPA acknowledges that not only did the affected facility definition expand to the collection of pumps at a site, but it also expanded to include piston pumps, which have not historically been regulated in NSPS OOOOa. Additionally, the proposed control options under NSPS OOOOb are completely unexpected and the hierarchy of options proposed would not have been a logical expectation based on the description in November 2021 proposal description. Specifically, operators have had no way of knowing:

1) Piston pumps would be affected facilities under §60.5365b(h).

2) The collection of both piston pump and diaphragm pumps would constitute an affected facility under §60.5365b(h).

3) The control standard would require a zero emissions control or a suite of ongoing certifications to demonstrate feasibility or infeasibility in §60.5393b.

4) Modification and reconstruction have never applied to such small ancillary equipment such as a single piston pump or diaphragm pump.

Therefore, the applicability date for pneumatic pumps under NSPS OOOOb should be the date of Supplemental Proposal.

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[82] Federal Register / Vol. 87, No. 233 / Tuesday, December 6, 2022 / Proposed Rules

8.2 Under NSPS OOOOb, we support the use of non-emitting pneumatic pumps for newly constructed well sites, tank batteries, and compressor stations, but we do not support the hierarchy of options proposed and inclusion of additional certification statements. The standard should be technology neutral similar to the pnuematic controller requirements.

The control options proposed for natural gas-driven pneumatic pumps are the same as those proposed to control natural gas-driven pneumatic controllers, yet the EPA is requiring additional technical demonstrations for pneumatic pumps that are not required for pneumatic controllers. We believe the requirements for natural gas-driven pneumatic pumps should be similar to those proposed for pneumatic controllers and the allowance for routing emissions to a control device which is allowed for pumps be extended to controllers (without any additional technical demonstration).

Furthermore, the hierarchal structure as proposed does not make logical sense as routing emissions to process, which has been a long-standing compliance option under the NSPS, is placed at a lower tier than that of implementing instrument air systems using solar or natural gas. As provided in Comment 12.9, the additional certifications associated with this hierarchy should be removed. The CAA already has provisions for knowing criminal violations related to false statements, which includes reference to false material statement, representation, or certification in/omits material information from/alters, conceals or fails to file or maintain a document filed or required to be maintained under the CAA.

8.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic pumps.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms ‘natural gas-driven pneumatic pump’ and ‘pneumatic pump’ interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic pumps. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric pumps as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(h)(1):

> *For the purposes of §60.5393b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic pumps at a site is increased by one or more.*

We offer the following suggested for modification redline to §60.5365b(h)(2):

> *For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic pumps in accordance with paragraph (h)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven pneumatic pumps at the site in accordance with paragraph (h)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (h)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (h)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic pumps is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of natural gas-driven pneumatic pumps”*

criterion in (h)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of natural gas-driven pneumatic pumps replaced exceeds 50 percent. For purposes of paragraphs (h)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of ~~component~~ natural gas-driven pneumatic pump replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic pump replacement.

(i) If the owner or operator applies the definition of reconstruction in §60.15, reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic pumps exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic pumps at the site. The "fixed capital cost of the new pneumatic pumps" includes the fixed capital cost of all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic pumps replaced, reconstruction occurs when greater than 50 percent of the pneumatic pumps at a site are replaced. The percentage includes all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]. If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic pumps that are replaced, the owner or operator must comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review also apply.

8.3.1 Additional clarifications are required for the proposed requirements for reconstruction of pneumatic pumps.

In review of the proposed regulatory text provided for §60.5365b(h)(2), the following elements of the proposed regulatory text require clarification:

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed.** Similar to natural gas-driven pneumatic controllers, the proposed language in §60.5365b(d)(2)(ii) suggests that reconstructed natural gas-driven pneumatic pumps would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic pumps. We believe it was EPA's intent to not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 proposal.

8.4 Suggested clarifications to certain proposed definitions related to pneumatic pumps in NSPS OOOOb and EG OOOOc.

While EPA expanded the applicability to include piston pumps, EPA did not include a definition for what a piston pump is or is not beyond the definition for natural gas diaphragm pump currently provided. Without this additional definition we request the following technical clarification as it applies to lean glycol circulation pumps. We do not believe it was EPA's intent to include these within the new zero-emitting provisions and historically EPA made it clear that this was not their intent to include these under NSPS OOOOa.

> ***Natural gas-driven diaphragm pump*** *means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a ~~diaphragm~~ pneumatic pump.*

8.5 The provisions included §60.5365b(h)(3) should also reference piston pumps.

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. We support EPA's retention of the provisions proposed in §60.5365b(h)(3) as these pumps will, by their very nature, result in very low and intermittent emissions. In the model plant analysis, the emissions for a single natural gas-driven piston pump is only 0.11 tpy VOC and 0.38 tpy methane. Temporarily used piston pumps would emit even less, which is why they have historically been exempt from the control standards. Such an exemption would be analogous to what also already been granted for temporary natural gas-driven diaphragm pneumatic pumps, and we believe it was EPA's intent to also include piston pumps in this provision.

We offer the following suggested redline to §60.5365b(h)(3):

> *A single natural gas-driven diaphragm pump or piston pump that is in operation less than 90 days per calendar year is not part of an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year in accordance with §60.5420b(c)(15)(i) and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.*

8.6 Natural gas-driven pneumatic pumps in compliance with NSPS OOOOa

NSPS OOOOa requires certain diaphragm natural gas driven pumps to be routed to a control device or process. As such, these pumps are already controlled by at least 95%. EPA has not adequately considered or accounted for how to handle these existing controlled pneumatic pumps within the proposed rules. Specifically, these pumps should meet the requirements of EG OOOOc by continuing to comply with NSPS OOOOa. These pumps should also be excluded from modification and reconstruction under NSPS OOOOa.

8.7 EPA's Model Plant Analysis for Conversion to Electric, Solar or Instrument Air Pumps

EPA assumptions for converting pneumatic pumps to zero-emitting has a distinctly separate set of cost assumptions from the pneumatic controllers even though the same technologies are being proposed for use. While EPA relied on costs from the 2016 and 2021 Carbon Limits report for pneumatic controllers, EPA uses different costs and assumptions as it pertains to converting to electric (assumed to be grid power) and solar pumps, which are not well documented and appear based on old information dating back to 2012. The EPA's economic feasibility analysis for pneumatic pumps presented in file "Supplemental TSD Ch 4 Pneumatic Pump.xlsx" are also only adjusted to 2019 USD from 2012 dollars. Thus, values presented are underestimated by at least 14%.[83]

9.0 Well Liquids Unloading Operations

As we communicated to EPA in our January 31, 2022 letter[84], well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective because there are numerous misconceptions about why and how this activity is conducted. While we support EPA's inclusion of well liquid unloading operations as an affected facility, the regulation should be based solely on the work practice standard outlined in §60.5376b(c)(2) and (d) and should not include a zero-emission limit as provided in §60.5376b(b). To this end, the recordkeeping and reporting requirements must be amended to be a workable framework for operators to assure compliance including removal of the certification statement by an engineer in every instance that venting may occur.

Lastly, the applicability for liquid unloading operations must be designated as the date of the Supplemental Proposal as the recordkeeping requirements were not explicitly known for each event that ocurred prior to the publication. Much of the recordkeeping elements proposed in the December 2022 proposal, including the certification statement by engineer, was not anticipated based on the descriptions in the November 2021 proposal.

9.1 Well liquid unloading operations should be subject to work practice standards and not held to a zero-emission limit.

API supports the proposed alternative measures outlined in §60.5376b(c)(2) and (d), which provide a clear and rational work practice standard based on Best Management Practices (BMPs) that achieve the intent to reduce

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[83] https://www.usinflationcalculator.com/

[84] EPA-HQ-OAR-2021-0317-0808

emissions from liquid unloading of gas wells. These provisions should be considered BSER and should not be considered an exception to the standard as currently proposed in §60.5376b(c).

We appreciate EPA's recognition that solely imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations that in many situations could severely halt natural gas production. For some situations, a certain unloading technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. The work practice standards proposed in §60.5376b(d) allow operators the flexibility needed to minimize emissions from well liquid unloading, while allowing for unexpected situations or outcomes that may occur during the unloading operation that might result in a minimal amount of emissions to be vented.

To be clear, while we support the work practice provisions in §60.5376b(c)(2) and (d), we do not support the provisions proposed in §60.5376b(b) establishing a zero-emission limit on liquid unloading operations as this limit creates undue burden of compliance when EPA has acknowledged it is known that not every liquid unloading operation can technically or safely meet the zero-emission limit. This undue burden is compounded when considering the logistical and practical implementation of the associated recordkeeping, reporting and certification statements also proposed. See also Comment 12.9.

9.2 Additional clarification to the proposed definition of liquids unloading is warranted.

As we previously commented in our January 31, 2022 letter, other well maintenance and workover activities may occur on a well that are distinctly different, require separate specialized equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. EPA must explicitly provide clarification to address these distinctions, within the definition for "liquids unloading" so not to confuse other activities that might occur at a well with the liquids unloading operation provisions as proposed.

Our suggested clarification to the definition of liquids unloading under §60.5430b and §60.5430c is as follows:

> *Liquids unloading means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production. Routine well maintenance activities, including workovers, screenouts, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.*

9.3 The recordkeeping and reporting for liquids unloading operations must be simplified into a manageable framework for operators and streamlined for liquid unloading operations that vent to atmosphere.

The information proposed by EPA within §60.5420b and §60.5420c for the recordkeeping and reporting as it pertains to liquid unloading operations is focused on an operator tracking and certifying techniques and less focused on allowing an operator to perform the necessary procedures to unload liquids accumulated within the wellbore and maintain natural gas production with as minimal emissions as possible. To address this shortfall, we suggest EPA define the data operators should track per unloading operation and remove all superfluous records that generate additional burden for the operator and EPA without added environmental benefit. These suggestions assume that liquid unloading operations are to be conducted using a work practice standard according to our suggestion in Comment 9.1.

The current proposed recordkeeping requirements do not offer a reasonable framework for operators to maintain compliance assurance. In fact, EPA has included a certification by professional engineer for every instance a well unloading operation vents emissions to atmosphere in §60.5420b(c)(2)(ii)(B) and §60.5420b(b)(3)(ii)(B) based on the proposed zero emissions limit standard. This may not be known to an operator until the liquid operation is taking place based on a variety of parameters. For context, a single well affected facility may undergo multiple liquid unloading operations in a single compliance period. For example, one well may necessitate an unloading schedule of four times in a year. Based on best management procedures, three (3) of these events may occur with zero emissions, while one (1) of the events might vent to atmosphere for a short duration using the same technique. The justification provisions in §60.5420b(c)(2)(ii)(B) are untenable when the same technique used on a well may resulted in zero emissions during some liquid operations, but not during all liquid unloading operations in the same compliance period. The fact is that in some instances a well liquid unloading operation may need to vent emissions for short duration, sometimes a little as 30 minutes, to safely perform the liquid unloading operation. We therefore request:

1) EPA remove the additional engineering certification statements under the guise of technical demonstrations. These additional certifications would be unnecessary if the standard followed a work practice procedure (see Comment 9.1).

2) Limit recordkeeping and reporting to liquid unloading operations that result in emissions only. This would reduce the administrative burden for thousands of liquid unloading operation events. This is also consistent with how both Colorado and New Mexico have organized recordkeeping and reporting for their state regulations.

   Our suggestions to streamline and simplify the recordkeeping and reporting for liquid unloading operations is as follows:

   > *For each gas well affected facility that conducts liquids unloading operations during the reporting period that resulted in emissions vented to the atmosphere:*
   >
   > - *US Well ID*
   > - *The number of liquids unloading events during the year that resulted in emissions.*
   > - *The date and time of each liquid unloading operation where venting occurred.*
   > - *The duration of venting in hours.*
   > - *Reason venting occurred*

Additional recordkeeping for liquid unloading operations should include:

> *Documentation of your best management practice plan developed under paragraph §60.5376b(d). You may update your best management practice plan to include additional steps which meet the criteria in §60.5376b(d).*

10.0 Compressors

API endorses the comments being submitted by GPA Midstream Association as it pertains to reciprocating and centrifugal compressors and provides the following additional comments.

10.1 Reciprocating and Centrifugal Compressors should be subject to a work practice standards with clear repair and delay of repair provisons instead of an emission standard.

Within Section IV.I.of the preamble (87 FR 74796), the EPA acknowledges *"over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder."* EPA also provides its rationale for the proposed level of excessive leaking (87 FR 747996) as "*the 2 scfm flow rate threshold was established based on manufacturer guidelines indicating that a flow rate of 2 scfm or greater was considered indicative of rod packing failure."* In summary, the EPA anticipates emissions from rod packings over time even from reciprocating compressors that are properly operated and maintained.

Yet, at the same time, EPA proposes to establish the 2 scfm flowrate as a not-to-exceed standard of performance, such that a violation occurs if flow rate exceeds that value (87 FR 74797). In doing so, EPA fundamentally misconstrues the manufacturers recommendations. In practice, exceeding a manufacturer-recommended flow rate is an indication that a repair should be made. Exceeding that rate does not necessarily compromise operability of the unit and, in fact, the values are selected to allow continued operation for the period necessary to arrange for needed repairs to be made. EPA without explanation proposes to transform what in practice constitutes an action level into a regulatory cap that cannot be exceeded without the prospect of incurring a violation. EPA's proposal is at odds with the facts and is an unreasonable reinterpretation of standard maintenance practices.

Therefore, if EPA is intent on setting a numeric standard of performance, the value must be well above the 2 scfm that EPA believes to be the standard manufacturer recommendations. The value must accommodate operations for a reasonable and potentially significant period of time that may be needed to accomplish needed repairs. If EPA takes this path, a reproposal is necessary so that we can know the newly proposed value, understand EPA's rationale, and have an opportunity to submit comments on the record. Alternatively, we believe that the flowrate can be established as a work practice that would trigger a repair obligation rather than constitute a numeric emissions limitation. While it is true that flow can be measured here, it is not technically or economically practicable to install measurement systems that would assure complliance with a numeric emissions limitation. See CAA § 111(h)(2)(B).

10.2 Clarification is required for compressors with multiple cylinders or seals.

In the November 2021 preamble (86 FR 63216), EPA described the rod packing requirements as follows:

> *"We are proposing that BSER is to replace the rod packing when, based on annual flow rate measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. We are proposing that if annual flow rate monitoring indicates a flow rate for any individual cylinder as exceeding 2 scfm, an owner or operator would be required to replace the rod packing."*

In looking at documentation for the dry seal proposed requirements, the Natural Gas Star[85] report where this value was seemingly derived, it is stated, "*During normal operation, dry seals leak at a rate of 0.5 to 3 scfm across each seal (1-6 scfm for a two seal system), depending on the size of the seal and operating pressure…. An example of one type of tandem seal with leak rates ranging between 0.5 to 3 scfm for 1.5 to 10 inch compressor shafts, for compressors operating at 580 to 1,300 psig pressure.*"

In the proposed text provided in §60.5380b or §60.5385b(a), the distinction that the limits are per cylinder or seal is unclear. It would be impratcical for a compressor with multiple cyclinders (reciprocating) or seals (centrifugal) to operate the same as compressor with only a single cyclinder or seal. As the Natural Gas star report documents, it is also impractical to expect the same level of emissions from dry seals for various sized units.

Therefore, EPA must clarify that the emission threshold designated is by cylinder or throw (reciprocating) and per seal (centrifugal). We note that the following suggested redlines for NSPS OOOOb and EG OOOOc are consistent with §95668 (c)(4)(D) of the 2017 California's GHG Emissions Regulations, which this proposed standard was based:

> *§60.5385b(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5393c(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5380b(a)(4)(i): The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section.*
>
> *§60.5392c(a)(1): You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. The volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm.*

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[85] https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/ll_wetseals.pdf

10.3 Conducting annual measurements on temporary compressors is logistically impractical and temporary compressors should be exempt from §60.5365b(b) and (c)(b).

Temporary compressors should be exempt from the monitoring requirments as it would be infeasible to conduct monitoring on a compresor that will be removed from a site after less than a year. Equipment that is intended for temporary use and is not a stantionary source should not not be subject to either NSPS OOOOb and EG OOOOc. API requests EPA make the following clarifications to address this concern:

> *§60.5365b(b): Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart. A centrifugal compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*
>
> *§60.5365b(c): Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart. A reciprocating compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*

10.4 Reciprocating Compressors

While API supports certain aspects of the Supplemental Proposal for reciprocating compressors, addiitonal clarifications must be made. The following amendments, in addition to the items outlined above and in comments submitted by GPA Midstream Association, would alleviate some of the significant technical cocnerns our members have with the proposed requirements.

- **Emissions from reciprocating rod packing vents that are routed to a process or flare should be considered an adequate alternative in reducing emissions.** EPA should continue to allow an option for rod packing vents to be routed to a control device for new, modified and existing facilities. The incremental benefit achieved between monitoring and subsequent repair (if applicable) versus capturing the vent to control device that achieves 95% destruction efficiency has not been substantiated by EPA within their cost benefit analysis. This is especially true for any compressor that already is designed and configured to route rod packing to a flare or other combustion device.

- **EPA should provide additional flexibility for addressing rod packing leaks by allowing operators to forgo annual emission measurements and replace rod packing annually.** Given the sheer number of compressors that will apply to NSPS OOOOb and EG OOOOc, EPA should provide flexibility by allowing operators the option to change out rod packing annually or 8760 hours (whichever comes first), which is similar in approach but more frequent than the current requirements in NSPS OOOO and OOOOa, or to perform the newly proposed annual monitoring and replacement of rod packing if emissions exceed to specific threshold as identified.

- **Repair parameters were omitted from the proposed regulatory text.** The EPA states their intent to define some repair parameters for reciprocating compressors in the preamble (87 FR 74798):

> *"The proposed NSPS OOOOb regulatory text also specifies that flow rate monitoring be conducted in operating or standby pressurized mode, and "repair" and "delay of repair" schedules, in addition to other clarifying requirements. The EPA is proposing to require conducting flow rate measurements during operating or standby pressurized mode because the measured emissions would be representative of actual emissions during operations. Repair schedules are proposed to require repair of equipment in a timely manner to mitigate emissions. Delay of repair would be allowed when owners and operators required more time to repair equipment based on scenarios beyond the owner or operator's control (e.g., issues with availability of equipment or where repair necessitates a compressor shutdown when redundancy of compressors is not available)."*

However, the repair and delay of repair schedules could not be located in the proposed regulatory text. As stated in Comment 10.1, the EPA should establish a monitoring schedule for reciprocating compressors with reasonable repair times. Further, allowances should be incorporated to address situations that delay repairs, appropriately.

California regulations governing rod packing emissions, upon which these proposed regulations are based, require repair within 30 calendar days from the date of the initial emission flow rate measurement. Furthermore, repair of a compressor typically cannot be performed while the compressor is in service, and some situations may arise that warrant delay of repair. We therefore request EPA amend the provisions in §60.5380b and §60.5385b to accommodate a work practice standard that includes clear provisions for repair or replacement and delay of repair or replacement that is consistent with §60.5397b(h)(3).

10.5 Centrifigal Compressors

10.5.1 Clarification is requested to the definition of centrifugal compressor.

Within the definition "centrifugal compressor" in §60.5430b and §60.5430c, EPA describes the compressor as "*discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers."* The phrasing of "significantly higher-pressure" should be further delineated to eliminate ambiguity. If left undefined the regulated operator does not have a clear understanding of what is affected and what is not affected.

The definition of centrifugal compressor as it was used in the initial NSPS OOOO rulemaking only affected wet-seal centrifugal compressors, which includes a relatively small population of affected facilities that were generally considered to discharge significantly higher-pressure natural gas. With the expansion of the NSPS OOOOb and EG OOOOc to also include dry seal compressors, which are more widely utilized, additional clarity is warranted.

In the oil and natural gas industry, compressors that boost natural gas pressures are normally designed to discharge natural gas greater than 300 pounds per square inch differential (psid). The original intent of EPA including this language was to exclude smaller compressors with low differential pressure (e.g., process compressors, vapor recovery units, and other low pressure service units). With this consideration, API recommends that EPA update §60.5430b to include a definition of significantly higher-pressure and includes the following language:

> *Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart. For the purposes of §60.5380b, significantly higher-pressure means having a design pressure differential greater than 300 pounds per square inch differential (psid).*

10.5.2 The emission limit for dry seal compressors should properly account for compressor size.

The origin of and basis for the proposed three (3) scfm limit for dry seal compressors is not provided within the EPA docket and associated references. API suspects that the genesis of this number did not consider variable compressor sizes, resulting in a low value for the standard that is not representative of all operations. In Section IV.G.1.b.iii of the Federal Register, the origin of this value is as follows: *"The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in §95668(d)(4-9), California's Regulations*[86] *for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate*[87]*."* Research into the underlying sources of the CARB regulation does not yield supporting information for the development of the 3 scfm standard. EPA should supplement the docket with information to support why this value is representative of the population of dry seal compressors across the nation (taking into consideration compressor size variability).

Larger compressors usually have larger shaft diameters, higher operating speeds, and greater operating pressures. These three variables all contribute factors to the amount of gas that might ultimately slip through the seals. The combination of these three factors will usually yield higher leak rates from seals as measured on a volumetric basis, thus larger compressors will have a higher baseline for normal operations.

Based on data submitted to the EPA pursuant to 40 CFR Part 98, Subpart W for the 2021 calendar year, dry seal compressor driver power output ranged between 5 – 42,000 horsepower and for wet seals the compressor driver power output ranged between 40 – 53,665 horsepower.[88] We do not believe compressors associated with the higher end of this range should be expected to operate the same as compressors closer to the lower end of this range. Table 2provides more details on our short analysis showing variable sizes of both dry and wet seal compressors as reference.

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[86] https://ww2.arb.ca.gov/sites/default/files/2020-03/2017 Final Reg Orders GHG Emission Standards.pdf

[87] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf, page 100.

[88] Information was extracted from EPA's Envirofacts database using the GHG query builder: https://enviro.epa.gov/query-builder/ghg.

Table 2. Variation in Compressor Driver Output as Reported under EPA's Greenhouse Gas Reporting Program for Calendar Year 2021

Compressor Horsepower Driver Details as reported to EPA for Calendar Year 2021	Count of Compressors in Dataset	Compressor driver power output (Horsepower)		
		Average	Minimum	Maximum
Dry Seals				
Onshore natural gas processing	310	6,427	5	38,000
Onshore natural gas transmission compression	812	14,431	144	42,000
Underground natural gas storage	19	9,817	5,700	15,280
Wet Seals				
Onshore natural gas processing	199	9,426	40	53,665
Onshore natural gas transmission compression	345	5,027	990	30,000
Underground natural gas storage	22	3,910	1,275	9,800

10.5.3 Additional clarification is needed regarding the volumetric flow.

Both wet seal and dry seal systems often use an inert gas, such as nitrogen, for system blankets at positive pressure. That nitrogen vents through the same vent as the seal gas. So measured total vent rates may be overestimating the amount of methane or VOC being vented to atmosphere. Actual vent rates of methane and VOC could be under the standard, but the total volumetric flow could be over due to the nitrogen blanket. EPA should make clear that the standard could be interpreted as either total volumetric flow or methane and VOC flow depending on which method of monitoring is employed.

EPA should also expand the volumetric flow measurement options to allow for alternative ways to obtain the methane and VOC flow:

- Use of thermal mass meter or ultrasonic meter readings in conjunction with gas composition samples to calculate methane and VOC flow, or
- Flow balance equations (i.e., if the amount of inert gas into the system is metered, then that volume could be subtracted from the total flow measurement, thus yielding the methane and VOC only flow.)

10.5.4 The wet seal centrifugal compressor requirements must be clarified between NSPS OOOOb and EG OOOOc.

It is unclear why the standards between NSPS OOOOb and EG OOOOc for centrifugal compressor standards are different:

- NSPS OOOOb – Dry seal compressors and "self-contained wet seal compressors" can only comply with volumetric standard. All other wet seal compressors can only comply with the 95% capture and control requirement.
- EG OOOOc – Any wet seal compressor can either comply with volumetric standard or reduce emissions by 95% through a control standard.

The implications of the NSPS OOOOb regulations seem to be that the 3 scfm volumetric standard is equivalent to the 95% capture and control requirement. If this is the case, then it stands to reason that all centrifugal

compressors should be able to choose to comply with either the volumetric standard or the 95% capture and control practice.

If owners of centrifugal compressors had the option to comply with either standard, it obviates the need for a specially defined class of compressors: “Self-contained wet seal compressors.” Removing this definition from the rule would result in a more simple and straightforward understanding of the rule requirements. API proposes the NSPS OOOOb standards mimic the EG OOOOc standards.

10.5.5 The proposed requirements for Wet Seal Centrifugal Compressors do not consider our previous comments regarding the unique equipment design in the Alaskan North Slope.

On the Alaska North Slope (ANS) there is not a market for natural gas sales. Most of the gas that is produced with the oil is separated and either used as a fuel or is compressed (using large wet seal compressors) to be reinjected back down hole for gas lift or enhanced oil recovery. The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.

Wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures most of the gas by volume then routes that gas to a flare, as described in our January 31, 2022 comment letter[89]. The ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum / tank, where any remaining entrained gas breaks out and is vented to atmosphere. In 2010, EPA’s Natural Gas Star[90,91] program, in conjunction with BP, conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis concluded that the sour seal oil degassing design employed on the ANS has greater than 99% emission control by volume. This same study is also cited by the CARB regulations references. It would stand to reason that this system of gas capture and control should be allowable to use the volumetric standard.

In summary, wet seal compressors with the sour seal oil traps in Alaska as described above, route the gas to the flare, not to the “compressor suction.” Because of this, these compressors would seemingly not meet the definition of “self-contained wet seal compressor.” However, there is language in that definition which suggests that the purpose of that definition is that degassed emissions do not route to atmosphere as proposed in §60.5430b and §60.5430c (***emphasis added***). Therefore, API offers the following redline for the definition of self-contained wet seal centrifugal compressor:

> *Self-contained wet seal centrifugal compressor means a wet seal centrifugal compressor system which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to either another process or combustion device* ~~*that is a closed process that ports the degassing emissions to the natural gas line at the compressor suction*~~ *(**i.e., degassed emissions are recovered**). The de-gas emissions are routed back to* ~~*suction*~~ *a process or combustion device directly from the intermediate closed degassing process* ~~*degassing/sparging chambers*~~*; after the intermediate closed process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.*

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[89] EPA-HQ-OAR-2021-0317-0808

[90] https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf

[91] https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf

Alternatively, as outlined in Comment 10.5.4, EPA could allow all centrifugal compressors the option to comply with the volumetric standard thereby obviating the need for a special definition for a “self-contained wet seal compressor.”

11.0 Leak Detection and Repair at Gas Processing Plants

API supports EPA’s proposal for bimonthly OGI monitoring for equipment leaks at gas processing plants. We also support incorporation of NSPS Vva into NSPS OOOOb and EG OOOOc as an alternative monitoring option with the additional simplifications EPA has proposed. While API also generally supports the use of Appendix K for OGI monitoring at gas processing plants, we have several comments with respect to proposed Appendix K as provided in Attachment A, which are in direct response to EPA’s solicitations within the preamble.

In addition to the above items, API offers the following comments concerning leak detection and repair requirements at gas processing plants.

11.1 Closed vent systems should be monitored annually using OGI or Method 21.

EPA is proposing initial and bi-monthly OGI or quarterly Method 21 monitoring of closed vent systems which are increased monitoring frequencies when compared with the existing annual Method 21 monitoring under NSPS OOOO, NSPS OOOOa, NSPS Vva, and other LDAR regulations. API’s previous comments on this topic[92] were intended to voice support for the use of OGI in monitoring closed vent systems and did not fully consider the implications and minimal environmental benefits of more frequent monitoring.

Closed vent systems have historically been subject only to initial and annual inspections due to their low leak rates. Closed vent systems rarely leak because of the small number of components and lack of constantly moving parts. The hard piping or ductwork in closed vent system do not experience the same wear and tear and potential for leaks as moving parts that generate friction. While OGI does not have the same proximity challenges as Method 21, more frequent monitoring of closed vent systems would still be impractical for both methods as parts of closed vent systems are considered difficult to monitor. More frequent inspections for closed vent systems at gas plants under NSPS OOOOb and EG OOOOc would also be more stringent than the requirements for refineries and chemical plants. Therefore, API recommends that for closed vent systems, hard piping be subject to an initial Method 21 or OGI inspection and annual AVO inspections and ductwork be subject to an initial Method 21 or OGI inspection and annual Method 21 or OGI inspections. If EPA decides to finalize the increased monitoring frequency for closed vent systems, they must provide additional justification including the additional environmental benefits expected from more frequent monitoring of equipment that rarely leak.

Emissions detected from closed vent systems do not constitute a violation of the “no identifiable emissions” standard provided work practice standards are fully implemented. See Comment 5.1 for a more detailed discussion.

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[92] EPA-HQ-OAR-2021-0317-0808

11.2 The lack of a VOC or methane concentration threshold expands monitoring requirements with minimal, if any, environmental benefit.

As API noted in its prior comments[93], EPA should retain the current 10 percent by weight threshold for VOC and propose a similar concentration threshold for methane, which we suggested as 1 percent by weight threshold for methane. In the Supplemental Proposal, EPA is proposing that monitoring apply to each piece of equipment "that has the potential to emit methane or VOC", which is effectively a zero-applicability threshold for both methane and VOC.

Some streams at gas processing plants contain methane or VOC but in such low concentrations that monitoring would be meaningless as it would likely always result in no detected emissions. Examples of such streams include but are not limited to purity ethane, acid gas, ancillary chemicals, wastewater, and recycled water. The proposed monitoring of additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with minimal, if any, environmental benefit.

In its existing LDAR regulations, EPA has recognized and reaffirmed the need for concentration thresholds to achieve cost-effective emission reductions. The agency has not provided sufficient justification for deviating from this longstanding practice with this rulemaking. Based on an initial review of EPA's TSD[94] from the November 2021 Proposal, API notes the following about EPA's analysis:

- EPA considers only components in VOC service and non-VOC service, which the agency appears to define as follows:

> *"In VOC service" is defined as a component containing or in contact with a process fluid that is at least 10 percent VOC by weight or a component "in wet gas service", which is a component containing or in contact with field gas before extraction. "In non-VOC service" is defined as a component in methane service (at least 10% methane) that is not also in VOC service.*

- EPA estimates VOC and methane emissions and therefore emission reductions and cost-effectiveness using only the following composition ratios identified in Table 10-8 of the TSD:

Component Service	Methane: TOC	VOC: TOC
VOC Service	0.695	0.1930
Non-VOC Service	0.908	0.0251

- EPA appears to treat the "potential to emit to methane" as equivalent to "in non-VOC service" in evaluating control options:

> *In addition to selecting one of the LDAR programs above, the EPA considered which components would be subject to the LDAR program. The current NSPS applies to components in VOC service (Option A). The EPA considered expanding the applicability to include components that have a potential to emit methane, which would add the components classified in this document as non-VOC service components (Option B).*

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[93] EPA-HQ-OAR-2021-0317-0808
[94] EPA-HQ-OAR-2021-0317-0166

Therefore, EPA does not appear to fully consider the cost-effectiveness of a potential to emit applicability threshold. API reiterates that EPA should retain the current 10 percent by weight threshold for VOC and establish a similar concentration threshold for methane (suggested as 1 percent by weight). Refer also to Attachment A.

In Comment 11.3, API offers recommended redlines to address this concern. Regarding how to determine when a piece of equipment is not subject to monitoring, the language in §60.5400b(a)(2) should also be revised as appropriate.

11.3 EPA should clarify which equipment is included in the evaluation of capital expenditure.

The definition of equipment is unclear on which equipment is considered when evaluating whether a capital expenditure occurred because capital expenditure is a definition, not a standard or requirement. This lack of clarity could lead to varying interpretations and uncertainty on whether a capital expenditure occurred. For other regulations, EPA has clarified the scope of equipment considered for the affected facility[95]. For leak detection and repair, an appropriate scope would be to apply the same definition of equipment to the capital expenditure evaluation as the standards and requirements. Therefore, the definition of equipment should clearly specify it also applies to capital expenditure.

To address this and the previous comment, API offers the following recommended redlines to definitions in §60.5430b.

> *Equipment, as used in the standards and requirements and for purposes of evaluating capital expenditure in section 60.5365b(f)(1) of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector ~~that has the potential to emit~~ in methane or VOC service and any device or system required by those same standards and requirements of this subpart.*
>
> *In methane service means that the piece of equipment contains or contacts a process fluid that is at least 1 percent methane by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in methane service.)*
>
> *In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in VOC service.)*

12.0 Overarching Legal Issues

12.1 The new source trigger date should be December 6, 2022, the date the Supplemental Proposal was published in the Federal Register.

In a memorandum associated with the Supplemental Proposal, EPA "solicits comments on whether CAA § 111(a) provides EPA discretion to define 'new sources' based on the publication date of the Supplemental Proposal and,

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[95] U.S. EPA Applicability Determination Index Control Number: 0600027, Modification and Capital Expenditure Calculations, dated February 9, 2001.

if so, whether there are any unique circumstances here that would warrant exercising of such discretion in this rulemaking by the EPA."

API believes that not only does CAA § 111(a) allow EPA to define the new source trigger date based on the publication date of the Supplemental Proposal, but also in fact requires it. Further, as API provides below, there are significant circumstances here that would warrant EPA altering the new source trigger date to December 6, 2022.

As explained in our January 31, 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) on the original NSPS OOOOb and EG OOOOc proposed rule, the original proposal was fundamentally incomplete because no proposed regulatory text was published or otherwise made available at the time of proposal. As a result, that proposal could not serve to set the new source trigger date for new requirements described in the proposed rule.

In the Supplemental Proposal, EPA reasserted that, except for newly proposed standards in the Supplemental Proposal (such as the standards for dry seal centrifugal compressors), the new source trigger date will be the date the original proposal was published in the Federal Register. EPA explains that "CAA Section 307(d)(3) specifies the information that a proposed rule under the CAA must contain, such as a statement of basis, supporting data, and major legal and policy considerations; the list of required information does not include proposed regulatory text." (87 Federal Register (FR) R 74716).

EPA further explains that "the Administrative Procedures Act (APA), which governs most Federal rulemaking, does not require publication of the proposed regulatory text in the Federal Register" and instead specifies that "notice of proposed rulemaking shall include ''*either* the terms or substance of the proposed rule *or* a description of the subjects and issues involved.'' (Emphasis added)." *Id*. EPA concludes that "the APA clearly provides flexibility to describe the ''subjects and issues involved'' as an alternative to inclusion of the ''terms or substance'' of the proposed rule." *Id*.

As an initial matter, EPA's analysis on this point indicates that EPA believes the CAA and the APA provide the flexibility to select November 15, 2021 as the trigger date for new sources, but nothing in EPA's analysis specifically concludes or determines that it must use the November 15, 2021 date. API believes that EPA's rationale for using November 15, 2021 remains flawed for three reasons. The lack of regulatory text (which was neither in the Federal Register notice nor otherwise made available in the docket prior to the close of the comment period) prevents the original proposal from setting the new source trigger date.

First, the CAA § 111(a)(2) definition of "new source" uses the term "proposed *regulations*" in defining the new source trigger date. As we explained in our comments on the original proposal, a preamble unaccompanied by regulatory text is not a "regulation." Here, the preamble to the original proposal was simply a description of the proposed regulations, but by itself did not constitute a proposed regulation because nothing in the preamble was intended by the Agency to constitute an enforceable legal obligation. And it could not, as EPA co-proposed multiple concepts for singular facility types in the November 2021 proposal and requested comment that informed the November 2022 Supplemental Proposal's regulatory text.

For example, in the November 2021 proposal, EPA co-proposed quarterly and semi-annual fugitive emissions surveys for well sites with baseline emissions of 3 or more and less than 8 tons per year of methane. EPA then abandoned the baseline emissions approach in the November 2022 Supplemental Proposal in favor of an equipment threshold. In another example, EPA co-proposed to define affected well facilities in two ways for purposes of the liquids unloading standards. Under one approach, every well that undergoes liquids unloading would be an affected facility; under the other approach, the affected facility would be limited to wells that

undergo liquids unloading that is not designed to eliminate venting. These co-proposals, while limited to a subset of the affected facilities, evidence that EPA intended the November 2021 proposal to be conceptual and a means of informing the November 2022 regulatory text.

The November 2022 proposal is complex and requires affected facilities to parse complicated standards that will inform significant capital expenditures and expensive compliance programs. Given the ultimate complexity of the November 2022 regulatory text and scope of impact, the November 2021 proposal's conceptual offerings did not put the regulated community on notice of the "regulations" in any meaningful way that could inform billions of dollars in capital expenditures and compliance program development. Instead, the regulatory text made available in conjunction with the Supplemental Proposal comprises the proposed regulation because that regulatory text defines the enforceable legal obligations that EPA proposes to impose under this rule.

Thus, even if the original proposal may have satisfied the nominal procedural requirements specified by CAA § 307(d) and APA § 553(b) (which it does not for the reasons explained below), the original proposal was not a proposed "regulation" for purposes of setting the new source trigger date under CAA § 111(a)(2). This is particularly true in light of the clear purpose of CAA § 111(a)(2), which is to put affected facilities that are constructed, reconstructed, or modified after the date of a proposed regulation on notice of the requirements that will apply to those facilities upon the effective date of the final regulation. The absence of proposed regulatory text in the original proposal prevents such affected facilities from knowing with reasonable certainty the precise requirements that might actually apply, and thus prevents them from adequately planning for compliance.

Second, EPA's interpretation of CAA § 307(d) and APA § 553(b) is unreasonable and does not make sense in the broader context of these provisions. For example, EPA argues that the required content of a proposed rule specified in CAA § 307(d)(3) does not expressly require regulatory text, but the corresponding content requirements for a final rule (specified in CAA §§ 307(d)(4)(B)(i), (6)(A), and (6)(B)) similarly do not expressly require regulatory text. By EPA's reasoning, that means that the Agency is not required to provide regulatory text as part of a final rule. That is nonsensical. This is particularly true because the record for judicial review is limited to the materials prescribed by CAA §§ 307(d)(3), (d)(4)(B)(i), (6)(A), and (6)(B). CAA § 307(d)(7)(A). If proposed and final rules do not need to include regulatory text, then regulatory text would not be subject to judicial review. That is contrary to reason and the clear intent of the law.

In short, it is simply not plausible to argue that because CAA § 307(d) does not expressly require a proposed rule to include regulatory text; EPA is not required to make proposed regulatory text available at the time of the 2021 "proposal". When considered as a whole, CAA § 307(d) plainly requires rule text to be available.[96]

Third, and more broadly, EPA and the Biden administration made a political judgment to rush issuance of the original proposed rule because the rule constitutes a prominent plank of the administration's climate change regulatory agenda, and it was deemed expedient to issue the proposed rule in conjunction with the 2021 Conference of the Parties to the United Nations Framework Convention on Climate Change in Glasgow, Scotland.[97] The fact that EPA acknowledged the original proposal would require a Supplemental Proposal with

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[96] EPA cites *Rybachek v. USEPA*, 904 F.2d 1276, 1297 (9th Cir. 1990) as supporting its position that proposed regulatory text is not necessary. That case is inapposite because the court relies on APA § 553(b)(3). While that provision applies to this rulemaking, the more specific requirements of CAA § 307(d) control here.

[97] EPA's press release for the original proposal is available at U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health | US EPA (""As global leaders convene at this pivotal moment in Glasgow for COP26, it is now abundantly clear that America is back and leading by example in confronting the climate crisis with bold ambition," said EPA Administrator Michael S. Regan**.** "With this historic action, EPA is addressing existing sources

actual regulatory text is plain evidence of the rush. The sheer size of the Supplemental Proposal – 146 pages in the Federal Register, *without* regulatory text (which is provided in the docket) – is further mute evidence of the incomplete nature of the original proposal.

We recognize that every administration has the right to set and implement its regulatory agenda. However, this Administration's desire to expedite issuance of the original proposed rule led to compromises in the usual regulatory procedures, including the decision not to make proposed regulatory text available. It would be unreasonable for affected facilities to bear the burden of those compromises. It is also arbitrary and capricious for EPA to decide to issue an admittedly incomplete proposed rule to satisfy political objectives, and, at the same time, assert that it is somehow complete enough to constitute a "proposed rule" that sets the new source trigger date.

As shown in the analysis above, nothing allows or requires EPA to utilize the November 15, 2021 date. Further, the failure of EPA to provide regulatory text in the November 15, 2021 proposal is reason enough for EPA to "warrant exercising" any discretion it does have with respect to the deadline.

Further, by utilizing November 15, 2021 as the relevant demarcation date, EPA will be including a significant number of sources that were new, modified, or reconstructed between November 15, 2021 and December 6, 2022. For a significant number of the affected facilities, operators will be required to retrofit those new, modified or reconstructed sources to comply with the regulations, including regulations not known to operators at the time of construction, modification or reconstruction. Many of these requirements involve either: (1) substantial capital expenditures for equipment (e.g., instrument air skids and/or generators for use of non-emitting pneumatic controllers); (2) engineering design (e.g., storage tanks, design for any covers and closed vent systems, among others); (3) acquisition (along with all other operators) of a substantial number of part and equipment (e.g., flow meters, calorimeters; and (4) substantial in-field resources for retrofits. Not knowing with reasonable certainty what the final rule would require would significantly complicate implementation of compliance measures, cause the rule to be much more costly for such sources than EPA predicts, and frustrate the regulatory purpose of setting the new source trigger date at the date of proposal (which clearly is intended to provide reasonable notice of the ultimate requirements so that planning can be done at the time of construction, reconstruction, or modification.

In addition, since the onset of the COVID pandemic and continuing to this day, there have been substantial supply chain disruptions, difficulty with obtaining parts and equipment and difficulty with finding personnel (either consulting or for employment) that can assist with implementation of the rule. These supply chain and personnel issues will increase given the extensive nature and reach of NSPS OOOOb alone (given all the operators that will need to comply) – not even accounting for other recent regulatory developments at the state and federal level (e.g., BLM waste prevention rule, Colorado regulatory requirements, and New Mexico requirements – to name a few). EPA will compound this supply chain and personnel concern by maintaining November 15, 2021 as the new source trigger date. EPA's motivation is further obscured given the sources constructed, modified or reconstructed between November 15, 2021 and December 6, 2022 are potentially subject to NSPS OOOOa and may ultimately be subject to EG OOOOc. Thus, API believes that EPA not only has the discretion but the requirement to assign December 6, 2022 as the new source applicability date. Even if this were not required, there is ample basis for EPA to do so for all the reasons previously stated.

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from the oil and natural gas industry nationwide, in addition to updating rules for new sources, to ensure robust and lasting cuts in pollution across the country. By building on existing technologies and encouraging innovative new solutions, we are committed to a durable final rule that is anchored in science and the law, that protects communities living near oil and natural gas facilities, and that advances our nation's climate goals under the Paris Agreement."").

12.2 EPA's interest in promoting Environmental Justice is laudable, but EPA must be mindful of the Clean Air Act's boundaries in advancing these goals.

API explained in its comments on the original proposal that we support EPA's attention to potential Environmental Justice (EJ) issues and agree with EPA that the emissions standards prescribed by this rule will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The oil and natural gas industry's top priorities are protecting the public's health and safety – regardless of race, color, national origin, or income – and the environment. We strive to understand, discuss, and appropriately address community concerns with our operations. We are committed to supporting constructive interactions between industry, regulators, and surrounding communities/populations including those that may be disproportionately impacted.

Our comments also explained that, while API supports EPA's EJ goals, the Agency did not provide sufficient detail in the 2021 Proposal to allow API to comment in a meaningful way. EPA has provided additional clarity on two key EJ provisions in the Supplemental Proposal. They are addressed separately below.

12.2.1 Consideration of EJ Impacts in CAA § 111 Standard Setting

First, EPA proposes to require consideration of impacted communities when setting existing source emissions standards that take into consideration remaining useful life and other factors (RULOF). For example, if "a designated facility could be controlled at a certain cost threshold higher than required under the EPA's proposed revisions to the RULOF provision, and such control benefits the communities that would otherwise be adversely impacted by a less stringent standard, the state in accounting for RULOF could choose to use that cost threshold to apply a standard of performance." (87 FR 74824).

EPA believes that it has authority to prescribe such a requirement because "CAA section 111(d) does not specify what are the "other factors" that the EPA's regulations should permit a state to consider", and thus the Agency may "interpret[] this as providing discretion for the EPA to identify the appropriate factors and conditions under which the circumstance may be reasonably invoked in establishing a standard less stringent than the EG." *Id*.

EPA further explains that part of its responsibility in reviewing the adequacy of state CAA § 111(d) existing source emissions control programs is to "determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives." *Id*. "The EPA finds that a lack of consideration to [disparate health and environmental impacts] would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally." *Id*.

Lastly, EPA explains that the "requirement to consider the health and environmental impacts in any standard of performance taking into account RULOF is consistent with the definition of "standard of performance" in CAA section 111(a)(1)" which "requires EPA to take into account health and environmental impacts in determining the BSER." *Id*.

We applaud and support EPA's overall objective of addressing potential disparate impacts. But we are concerned that the Agency's proposal to require such impacts to be addressed when RULOF is considered in setting state standards is not legally supportable.

To begin, the term "other factors" is a generic term in and of itself. But as used in the context of CAA § 111(d), that term does not reasonably mean that EJ may be considered in standard setting. First, CAA § 111(d)(1) states that EPA's regulations "shall permit" states to consider RULOF in setting existing source emissions standards. This

language places responsibility on the states, in the first instance, to determine the "other factors" they deem relevant in setting standards upon consideration of RULOF. EPA's role is to review the state determination and not to preemptively specify what factors a state may or may not consider. If a state's identification and consideration of other factors is reasonable, then EPA cannot reject the state's determination on the grounds that EPA believes the term "other factors" should be given a different meaning. EPA's proposed approach is inconsistent with the role Congress intended the states to fulfill as part of the CAA's broader "cooperative federalism" scheme.

Second, the term "other factors" must be interpreted in context. By specifying that states may consider "remaining useful life," Congress indicated that source-specific factors are relevant to the states' determinations. Since the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term "other factors" must be construed in a similar light. This interpretation is particularly true given that "standards of performance" under CAA § 111(a)(1) are technology-based standards that reflect the best system of emissions reduction determined applicable to affected facilities. EPA's proposed interpretation of "other factors" is inconsistent with this source-specific, technology-based regulatory scheme.

Third, unlike other standards under the CAA, CAA § 111 does not require or allow for standards to be based on an assessment of impacts regarding health or the environment. Where the CAA confers such authority, it does so expressly and usually in a context where criteria exist to determine the adequacy of such standards. For example, CAA § 112(f) requires impacts to health and the environment to be considered in determining whether "MACT"[98]-based NESHAPs are adequately protective to health and the environment. The statute specifies that EPA must provide an "ample margin of safety," as defined in the Benzene Waste NESHAP. CAA § 112(f)(2)(A), (B). The Title I air quality program is also designed in this fashion – with the National Ambient Air Quality Standards (NAAQS) established as the benchmark for acceptable air quality and the guidepost for formulating appropriate state programs.

Here, CAA § 111 does not provide any indication that EPA must or may consider health or environmental impacts associated with air emissions from affected facilities in determining BSER and in setting emissions standards. For over 50 years, CAA § 111 has properly been construed as a technology-based program designed to prescribe standards based primarily on consideration of the best available technologies that are adequately demonstrated and not cost prohibitive. EPA's goals here are important but would require standards to be based on impacts analyses of air emissions from affected facilities – an approach that is not incorporated into the CAA § 111 standard setting process.

EPA also states that not considering impacts would be "antithetical to the public health and welfare goals of CAA Section 111(d) and the CAA generally." There is no doubt that protecting public health and welfare are overarching goals of the CAA. That aspiration does not in itself confer regulatory authority that is not otherwise prescribed by the statute. Congress carefully designed the regulatory tools it intends EPA to use to accomplish an adequate degree of protection to health and welfare. For the reasons explained above, CAA § 111(d) does not require or allow for consideration of health or environmental impacts in standard setting.

Lastly, EPA argues that considering EJ impacts in state standard setting "is consistent with the definition of "standard of performance" in CAA Section 111(a)(1)" and that states must consider such impacts "just as the EPA is statutorily required to take into account these factors in making its BSER determination." *Id*. at 74824. More specifically, EPA asserts that the definition of "standard of performance" "requires the EPA to take into account health and environmental impacts in determining the BSER." *Id*. We respectfully disagree, as there is no language

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[98] Maximum Achievable Control technology

in the CAA § 111(a)(1) definition of "standard of performance" that requires or allows health or environmental impacts associated with air emissions from affected facilities to be factored into standard setting.

As explained above, that definition requires standards of performance to primarily be based on technology and cost considerations. The only exception is that "nonair quality health and environmental impact[s] and energy requirements" also must be taken into account in setting standards of performance. CAA § 111(a)(1). The statute thus is clear that the only "health and environmental impacts" that may be considered in setting a standard of performance are ***nonair*** health and environmental impacts. That provision traditionally has been interpreted to require EPA to consider cross-media impacts (e.g., wastewater created by an air emissions scrubber) so as not to create a different environmental issue through technical requirements meant to address air quality. Because the analysis that EPA would require here would focus on air emissions impacts, it cannot be grounded in the requirement to consider ***nonair*** quality health and environmental impacts. Moreover, because the statute specifies that only nonair quality health and environmental impacts may be considered in standard setting, EPA is precluded from interpreting general language in CAA § 111(a)(1) or 111(d)(1) as somehow authorizing consideration of air quality-based health or environmental impacts.

For all of these reasons, EPA should reconsider the proposed requirement to require consideration of EJ impacts when states or EPA implement the RULOF provision.

12.2.2 Requirement that states provide for "meaningful engagement" in their CAA § 111(d) programs.

The Supplemental Proposal provides further details and additional explanation of the proposal to require states to provide for "meaningful engagement" as part of their CAA § 111(d) regulatory programs. According to EPA, "[t]he fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare" (87 FR 74827). As a result, EPA asserts that "a key consideration in the state's development of a state plan, in any significant plan revision, and in the EPA's development of a Federal plan pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare." *Id*. "A robust and meaningful public participation process during plan development is critical to ensuring that the full range of these impacts are understood and considered." *Id*.

The "meaningful engagement" requirement is grounded in the assertion that "a fundamental purpose of the Act's notice and public hearing requirements is for all affected members of the public, and not just a particular subset, to participate in pollution control planning processes that impact their health and welfare." *Id*. at 74828-9. In explaining the legal basis for this requirement, EPA states that "[g]iven the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, the EPA believes it is reasonable to require meaningful engagement as part of the state plan development public participation process in order to further these objectives." "Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations ''as are necessary to carry out [its] functions under [the CAA].'' The proposed meaningful engagement requirements would effectuate the EPA's function under CAA section 111(d) in prescribing a process under which states submit plans to implement the statutory directives of this section." *Id*. at 74829.

API supports full and fair public process in the development and implementation of CAA programs, including state CAA § 111(d) programs. All affected entities should have a reasonable opportunity to know about and participate in the development of regulations that affect their interests. In that light, we offer the following comments on the proposed "meaningful engagement" requirement.

First, CAA § 111(d) states only that EPA shall establish a "procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan." This requirement to establish a "procedure" for "submit[ting] … a plan" unambiguously is directed only at the review and approval process as between the states and EPA and is not directed at the plan development process that must be followed by the state. In other words, CAA § 111(d) directs EPA to emulate only some of the CAA § 110 requirements – not all of them.

Thus, CAA § 111(d) does not allow EPA to impose upon the states any measures related to the process by which they develop their plans. It only provides authority to set up a process by which EPA reviews and approves the adequacy of standards of performance and the measures adopted by the states to implement and enforce such standards.

Second, to the extent that a "reasonable notice" standard applies to the development of state plans under CAA § 111(d), it is the states' responsibility to ascertain what is reasonable – not EPA's. CAA § 111(d) is one of many CAA provisions where Congress intentionally split responsibility between EPA and the states. Indeed, under this "cooperative federalism" scheme, "air pollution control at its source is the primary responsibility of States and local governments." CAA § 101(a)(3). In the earliest days of the CAA, the U.S. Supreme Court confirmed that the CAA "gives the Agency no authority to question the wisdom of a State's choices of emission limitations" if the limitations accomplish the goals of the CAA. *Train v. NRDC*, 421 U.S. 60, 79 (1975).

Implicit in the notion of cooperative federalism is that states not only have wide latitude to determine appropriate emissions limitations, but also have similarly wide latitude in the legal and regulatory processes by which such limitations are established. Thus, to the degree a "reasonable notice" obligation is imposed upon the states by CAA § 111(d), the states have primary authority and responsibility to determine how to implement this requirement. While EPA has responsibility to review and approve state programs, it may not require states to follow what it believes to be the most reasonable notice procedures. Instead, EPA must approve any state notice requirements that are facially reasonable, even if those are not the procedures EPA itself would have selected.

Third, even if EPA has authority to define what constitutes "reasonable notice" during the development of state plans, the proposed "meaningful engagement" requirement goes beyond what EPA may reasonably require. To begin, the term "notice" unambiguously means notification of those with interest in the matter at hand. The proposed requirements to engage with particular groups in particular ways (e.g., states must seek to overcome "barriers to participation" by "pertinent stakeholders") and make targeted outreach go well beyond the nominal statutory obligation of notification. EPA may "think [its] approach makes for better policy, but policy considerations cannot create an ambiguity when the words on the page are clear." *SAS Institute Inc. v. Iancu*, 138 S. Ct. 1348, 1358 (2018). Congress has imposed no explicit requirements and stated no intent in CAA § 111 or anywhere else in the CAA related accomplishing any particular environmental justice goals or outcomes. The word "notice" cannot carry as much meaning as EPA believes it should.

As for CAA § 301, it has long been understood that that provision does not "provide [EPA] Carte blanche authority to promulgate any rules, on any matter relating to the Clean Air Act, in any manner that the [EPA] wishes." *North Carolina v. EPA*, 531 F. 3d 896, 922 (D.C. Cir. 2008) (internal quotes and citations omitted). Here, CAA § 301(a)(1) is inapplicable because creating a new category of procedural requirements is not "necessary" for the Administrator "to carry out his functions under this chapter." CAA § 301(a)(1). As noted above, EPA's intentions are commendable. But the proposed "meaningful engagement" procedures are not "necessary" as that term is used in CAA § 301.

Lastly, EPA's proposed "meaningful engagement" procedures are are not adequately clear and objective. As noted above, Congress has not spoken in the CAA to the issue of environmental justice. EPA and interested parties are without guidance as to whether the issue should be addressed under the CAA and, if so, how.[99] Moreover, EPA's criteria for determining the adequacy of state "meaningful engagement" efforts are vague and EPA's authority under its proposed rules to accept or deny a state's efforts is not bounded by any readily objectively discernable principles. For example, how does EPA determine the manner of required engagement with any particular stakeholders? How does EPA decide what constitutes an actionable "linguistic, cultural, institutional, geographic, [or] other barrier" and, where such barriers are determined to exist, whether the state's proposed approach is sufficient? What measures are needed for state programs to be adequately inclusive? These are all weighty questions that the statute does not expressly address and that EPA leaves fundamentally uncertain in its proposed rule. As a result, the proposed rule is vague, unmoored to the statute, and unless corrected, would be arbitrary and capricious. *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983).

For these reasons, "meaningful engagement" should be encouraged by EPA but cannot be a required element of approvable state CAA § 111(d) programs.

12.3 EPA does not explain the legal basis for its proposal to empower third parties to conduct remote monitoring that may trigger enforceable obligations by affected facilities.

In the original proposal, EPA presented a preliminary concept that would "take advantage of the opportunities presented by the increasing use of [advanced methane detection systems] to help identify and remediate large emission events (commonly known as "super-emitters")" (86 FR 63177). EPA sought comment on "how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event." *Id*.

As we explained at the time, API concurs with the importance of identifying and addressing large emissions events. Emissions from such events have the potential to be much greater than those from normal operations at a given facility. API shares EPA's interest in seeking to reduce the incidence of such large emissions events.

We noted in our comments that the proposed "Super Emitter Response Program" was unique in that it would be the first time under the CAA that EPA asserts authority to create regulatory obligations for affected facilities based on monitoring conducted by unaffiliated third parties. We further noted EPA did not explain the legal basis for establishing such a requirement and explained that an explanation from EPA was essential to understanding whether such a novel provision is legally viable.

Unfortunately, the Supplemental Proposal does not provide the needed explanation. That failure to explain the legal underpinnings of such a key element of the proposal violates the CAA § 307(d)(3)(C) requirement to include as part of the proposed rule "the major legal interpretations underlying the proposed rule." If not cured, it also would render the final rule arbitrary and capricious because EPA would have failed to address and explain a key factor underlying this aspect of the final rule.

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[99] It is notable that the 2022 "Inflation Reduction Act" included the most significant amendments to the CAA in decades and specifically targeted Environmental Justice concerns, yet Congress stopped short of amending CAA § 111 or the other existing substantive CAA programs to require or allow consideration of EJ. In other words, Congress expansively addressed EJ, but did so by providing copious funding to address the issue and chose not to create obligation or authority to otherwise address or consider EJ in implementing the existing CAA substantive programs.

To be sure, the Supplemental Proposal includes a lengthy discussion in the preamble called the "Statutory Basis of Super-Emitter Program" (87 FR 74752). For some four pages, EPA delves deeply into two explanations as to how it believes "the proposed super-emitter response program … fits within the EPA's authority under section 111 of the CAA." *Id*. In particular, EPA explains how the program might be justified by treating super-emitting events as an affected facility warranting a § 111 emissions standard and, alternatively, how the "super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule" (either as an added compliance assurance measure or as additional equipment leak work practices). *Id*. at 74752-4.

As for those suggestions, API disagrees with EPA's contention that it has authority to treat super-emitting events as an affected facility warranting a § 111 standard of performance. Rather, at most, EPA has the authority to consider identification of super-emitter events as "monitoring" for an affected facility. As such, super-emitters may only be regulated at facilities that already are subject to NSPS OOOOb or EG OOOOc for other reasons. In other words, if a thief hatch on an NSPS OOOOb storage vessel were left open, it could (if meeting the threshold – and subject to the legal concerns set forth below) be considered a super-emitter, and EPA could require corrective action to close the thief hatch. This would be similar for emissions above the threshold from an unlit flare or control device that is mandated by NSPS OOOOb or EG OOOOc (once applicable). However, a super-emitter cannot arise from equipment at a stationary source that is not already an affected facility.

In other words, if an aerial survey identified emissions from a thief hatch on a storage vessel that is not subject to NSPS OOOOb, and the storage vessel is not yet subject to EG OOOOc, then this cannot be a super-emitter affected facility subject to the regulations and for which an operator has to take corrective action. EPA's preamble appears to support this approach in several places, but does not specifically state this in the rule. Thus, as written, it appears that one could identify a super-emitter at a stationary source that has no affected facilities or from equipment that is not an affected facility. EPA has not justified that super-emitters – many of which are malfunctions – are or can be independently considered "affected facilities" under CAA § 111.

An in any event, nowhere in this lengthy discussion – nor in any other part of the preamble or supporting documents – does EPA explain where in the CAA it finds authority to empower third parties to submit monitoring information to an affected/designated facility that triggers regulatory obligations for the facility under the rule. The need for a legal explanation is particularly necessary here, given that this is the first time that EPA has sought to establish such a requirement under CAA § 111 or, to our knowledge, under the CAA as a whole.

We also note that EPA provides a lengthy discussion of the policy rationale that stands behind the proposed Super-Emitter Response Program, including an extensive explanation of how EPA believes that "[t]he design of the super-emitter response program ensures that the EPA will make all of the critical policy decisions and fully oversee the program." *Id*. at 74749-51. In EPA's view, "the qualified third party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications within the limited confines that EPA has authorized." *Id*. at 74750. Moreover, such notifications "originating from third parties would not represent the initiation of an enforcement action by the EPA or a delegated authority." These arguments indirectly speak to EPA's assertion of possible legal authority, but the policy rationale by itself cannot legally justify EPA's novel proposal to empower citizens to develop and submit information that triggers legal obligations for affected/designated facilities.

We lastly note that, in our comments on the original proposal, we explained that CAA § 304 expressly prescribes a role for citizens in CAA implementation by authorizing them to file civil lawsuits challenging alleged violations of, among other things, CAA § 111 emissions standards. We pointed out that Congress did not provide similar express

language in CAA § 111 or elsewhere in the CAA authorizing citizen monitoring as provided in the proposed super-emitter response program. In this context, the absence of such language should be construed as a limitation on EPA's authority to allow such monitoring and such an absence is not an implicit delegation of authority from Congress to EPA.

As a further note on the relevance of CAA § 304, that section prescribes strict criteria for obtaining injunctive relief to address alleged CAA violations – including prior notice, opportunity for the government to take the lead on an enforcement action, standing to bring an enforcement case, proof of liability, and sufficient rationale to support injunctive relief. The proposal runs counter to CAA § 304 by enabling citizens to obtain injunctive relief through the super-emitter response program (in this case, investigation, corrective action, root cause analysis, and related measures) without satisfying the procedural and substantive criteria that must be met to obtain such relief under CAA § 304.

12.4 The 100 kg/hr emissions threshold for defining a "super-emitter" is not adequately justified.

As a wholly different concern, EPA proposes to "define a super-emitter emissions event as any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater." *Id*. at 74749. While EPA provides a lengthy explanation of how that threshold was determined and why EPA believes it is appropriate, the overarching rationale is that the Agency believes that this threshold captures "very large emissions events." *Id*. Indeed, the term "super-emitter" clearly was coined to describe the intended scope of coverage.

Yet just a few months ago, when addressing essentially the same issue under Subpart W of the Greenhouse Gas Reporting Program, EPA proposed to establish a new reporting requirement for "other large release events," which EPA proposed to define as "events that release at least 250 mtCO_2e per event." 87 Fed. Reg. 36920, 36982 (June 21, 2022). In explaining its rationale for setting this threshold, EPA explains that, "[w]hile some sources covered by subpart W methodologies, such as equipment leaks, may represent ''malfunctioning'' equipment, these sources are ubiquitous across the oil and gas sector [and] are generally small." *Id*. The proposed 250 mt reporting threshold is intended to capture "large emissions events." *Id*. EPA derived the value by assessing "other emissions sources that [it] considered large." *Id*. The threshold was expressly designed to be considerably lower than the emissions rates estimated for the largest release events (e.g., Aliso Canyon or Ohio well blowouts), and compares favorably to a similar reporting requirement under Subpart Y for petroleum refinery flares. *Id*. at 36983.

Despite the obvious similarities between the proposed Subpart W large emissions event proposal and the proposed NSPS OOOOb and EG OOOOc super-emitter proposal, EPA fails to mention the Subpart W proposal when explaining in the NSPS OOOOb and EG OOOOc proposal its rationale for establishing the emissions threshold for super-emitting events. The omission is particularly striking given the significant differences between the two proposals as to what EPA believes to be a large-emitting event. For example, EPA proposes to apply a kg/hr metric in NSPS OOOOb and EG OOOOc versus an event-based metric for Subpart W. Additionally, the proposed NSPS OOOOb and EG OOOOc threshold of 100 kg/hr is facially much lower than the 250 mt per event threshold in Subpart W. The Subpart OOOOb and OOOOc proposal would define events as "super-emitting" that EPA in the Subpart W proposal dismisses as "ubiquitous" and "generally small."

Clearly, the two proposed rules are contradictory in many relevant aspects. EPA has not provided any explanation in the NSPS OOOOb and EG OOOOc original or Supplemental Proposals as to why the proposed definition of "super-emitter" makes sense in light of the proposed rules for large event release reporting under Subpart W.

Lack of such an explanation would render this aspect of the final NSPS OOOOb and EG OOOOc rule arbitrary and capricious. Moreover, even if EPA provides an explanation in the final rule, the definition of "super-emitter" is of central relevance to the Super-Emitter Response Program and, thus, failure to provide an opportunity for public notice and comment on its explanation would violate the CAA § 307(d) procedural rulemaking requirements.

12.5 EPA's proposed approach to reconciling the applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc is contrary to law and unreasonable.

In our comments on the original proposal, we noted that the proposal did not include any discussion or analysis of the complex issues surrounding the applicability of the various NSPS OOOO subparts. We pointed in particular to the complexities related to the fact that the various subparts do not completely overlap – Subpart OOOO applies only to volatile organic compounds (VOCs), Subparts OOOOa and OOOOb apply to VOCs and greenhouse gases (GHGs), and EG OOOOc applies only to GHGs. Also, the affected/designated facilities are not the same under these rules. We also highlighted the question of whether a source that is an affected facility that is regulated as a new source under an existing NSPS can also be an "existing" facility under a subsequent CAA § 111(d) rule. Another important omission was any citation or explanation/analysis by EPA of the applicable law.

The Supplemental Proposal does not resolve these issues. To be sure, EPA provides an explanation of how it believes "the proposed EG OOOOc [will] impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa." (87 FR 74716). But that explanation is fundamentally incomplete because EPA still does not provide any legal analysis explaining how or why its proposed analysis is required or allowed under the law. The full extent of EPA's legal discussion on this topic is the conclusory assertion that:

> *Under CAA section 111, a source is either new, i.e., construction, reconstruction, or modification commenced after a proposed NSPS is published in the Federal Register (CAA section 111(a)(1)), or existing, i.e., any source other than a new source (CAA section 111(a)(6)). Accordingly, any source that is not subject to the proposed NSPS OOOOb as described is an existing source subject to EG OOOOc.*

Id. at 74716.

That simple explanation does not provide sufficient detail on the key legal questions we presented in our prior comments. For example, EPA does not explain how the law requires or can be interpreted to require a source to be regulated as a "new" source under a prior NSPS and, at the same time, be regulated as an "existing" source under a subsequent CAA § 111(d) program. It is clear that EPA presumes that this is how the law works. For example, the Agency repeatedly asserts that Subpart OOOOc standards "would satisfy compliance with" previously applicable NSPS – clearly implying that both standards would apply. See *Id.* at 74716-8. But the Supplemental Proposal does not explain why this outcome (applicability of both new and existing source standards to the same affected/designated facility) must or may be prescribed under the law.

EPA's silence on this important matter is particularly pronounced because EPA has never taken the position a that previously applicable NSPS continues to apply to an affected facility that triggers the applicability of a subsequent standard. For example, VOC emissions from storage vessels are regulated under both Subpart OOOO and Subpart OOOOa. It is easily conceivable that a given storage vessel might have triggered Subpart OOOO because it was constructed one month after that standard was proposed and then subsequently triggered Subpart OOOOa because the storage vessel was modified two months after that standard was proposed. It is well understood that, in such a circumstance, the Subpart OOOO storage vessel requirements cease to apply after the corresponding

Subpart OOOOa requirements are triggered. The approach to reconciling applicability suggested in the Supplemental Proposal cannot be reconciled with EPA's historic practice.

More broadly, EPA fails in both the original and Supplemental Proposals to explain how the law must or can be construed to determine what standard applies to a given source when: (1) the source is regulated as a new source under a prior version of an NSPS (such as Subpart OOOO) and then triggers a subsequent version of that new source standard (such as Subpart OOOOa); (2) the source is regulated as a new source under an existing new source standard (such as Subpart OOOO or OOOOa) and is in existence when a subsequent Section 111(d) existing source standard is proposed (such as EG OOOOc) and subsequently take effect; and (3) a source is regulated as an existing source under a Section 111(d) standard (such as EG OOOOc) and is subsequently modified or reconstructed such that it triggers a corresponding new source standard (such as NSPS OOOOb).

In sum, EPA fails to acknowledge the complexities and ambiguities as to how the law applies to this situation and fails to provide relevant legal analysis on these points. Unless EPA corrects these problems, the final rule will be both procedurally flawed (for failure to satisfy the CAA § 307(d)(3) obligation for EPA to address in the proposed rule that major legal interpretations underlying the proposed rule and to provide an opportunity for public comment) and arbitrary and capricious (for failure to address key factors underlying applicability of the various subparts). We note the legal basis for the applicability scheme for these rules is an issue of central relevance because the scope of applicability is fundamental to proper implementation and coordination of these rules.

12.6 EPA must provide more flexibility for approving state programs.

The Supplemental Proposal includes a lengthy discussion of the approach and criteria by which EPA proposes to review and approve/disapprove state CAA § 111(d) existing source programs. We have comments and recommendations on several elements of EPA's proposed approach.

All of our comments flow from the fundamental guiding principle that EPA is required to approve state programs that satisfy CAA § 111(d) standard setting criteria and cannot approve state programs that do not meet those criteria.[100] EPA correctly sums up this principle when it states "that its authority is constrained to approving measures which comport with applicable statutory requirements" (87 FR 74826 n. 274). The problems with EPA's proposal regarding approval of state programs all are grounded in violations of this principle.

To begin, EPA exceeds its authority by seeking in many places to impose its own preferences on state programs rather than recognizing that it must approve any state program that meets the statutory criteria – even programs that include elements that EPA itself would not choose, but that objectively do meet statutory standard setting requirements. In other words, if a state program meets express statutory requirements or otherwise is grounded on a reasonable construction of statutory requirements, EPA has no choice but to approve the program.

For example, EPA repeatedly and wrongly asserts that its "presumptive standards" must be used to judge the adequacy of state programs. See, e.g., *Id*. at 74812 ("a state program must establish standards of performance that are in the same form as the presumptive standards"); *Id*. ("EPA is also proposing to interpret CAA section 111 to authorize states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards"). Using EPA's presumptive standards as a measure of acceptability is wrong because a state's obligation under CAA § 111(d) is to establish standards of performance based on BSER.

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[100] The only other state obligation is to satisfy the nominal procedural requirements that EPA establishes for submission, review, and approval of state CAA § 111(d) programs.

CAA §§ 111(a)(1) and (d)(1). EPA's "presumptive standards" do not constitute BSER. Rather, they represent EPA's notion of what emissions standard might reasonably satisfy EPA's BSER determinations. But the statute unambiguously provides that states have authority and responsibility to fashion a standard that meets BSER and is not limited to the "presumptive standard" that EPA thinks is best.

Notably, EPA clearly understands that is what the statute requires. EPA itself states that "Section 111(d) does not, by its terms, preclude states from having flexibility in determining which measures will best achieve compliance with the EPA's emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion" (87 FR 74812). EPA's acknowledgment that it is the states' obligation to determine what measures "best" satisfy EPA's BSER determination is a correct statement of the law and contradicts the idea that EPA gets to decide what is "best" and impose that judgment on the states.

On a related note, EPA here indicates its commitment to faithfully implementing the "framework of cooperative federalism that CAA section 111(d) establishes," which necessarily requires EPA to defer to (and approve) state measures that satisfy the law, even when such measures do not satisfy EPA's own preferences. See also *Id*. at 74826 (EPA proposing to defer to the state's discretion to impose more costly controls). Yet on the other hand, a primary rationale for the proposed prescriptive measures for reviewing and approving/denying state programs is concern about inconsistency from state to state (e.g., *id*. at 74818 ("two states could consider RULOF for two identically situated designated facilities and apply completely different standards of performance on the basis of the same factors")) and the possibility that certain state programs will be less stringent than EPA believes they should be (e.g., *id*. at 74817 (lack of a clear framework might allow states to "set less stringent standards that could effectively undermine the overall presumptive level of stringency envisioned by the EPA's BSER determination and render it meaningless")). EPA cannot have it both ways – i.e., support state flexibility when it promotes EPA's preferred outcomes and discourage state flexibility when needed to achieve such outcomes. Such an inconsistent approach is facially arbitrary. It is easily resolved by allowing the state flexibility that EPA acknowledges to exist and, in any event, that is demanded by the statute.

Another flaw in EPA's approach is its proposal to give substantive meaning to the statutory obligation that it must approve state plans that are "satisfactory." CAA § 111(d)(2)(A). For example, EPA explains that "it is the EPA's responsibility to determine whether a state plan is "satisfactory" (87 FR 74818). EPA further explains that "the most reasonable interpretation of a ''satisfactory plan'' is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d)." *Id*. See also *id*. at 74824 ("CAA section 111(d)(2)'s requirement that the EPA determine whether a state plan is ''satisfactory'' applies to such plan's consideration of RULOF in applying a standard of performance to a particular facility. Accordingly, the EPA must determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives.").

So, by EPA's reasoning, all elements of its CAA § 111(d) implementing regulations become mandatory state obligations because, if a state does not in EPA's eyes satisfy the regulations, the state program is not "satisfactory" to EPA. Similarly, EPA gets to decide whether a state plan is "satisfactory" based on EPA's judgment as to whether the plan meets EPA's conception of the "overall health and welfare objectives" of CAA § 111(d). In other words, EPA uses the term "satisfactory" to bootstrap its own policy and legal preferences into mandatory approvability criteria.

EPA's interpretation is inconsistent with the plain words of the statute and, in any event, unreasonably expands EPA's authority to prescribe or prohibit particular outcomes under state CAA § 111(d) programs. The statute

simply says that state plans must be "satisfactory." The word "satisfactory" naturally connotes that EPA must approve any state plan that meets the statutory standard setting criteria and that otherwise meet the nominal procedural rules that EPA is required to establish to guide submission and review/approval of state plans. The word "satisfactory" does not reasonably confer upon EPA the authority to demand particular outcomes (e.g., meeting EPA's self-determined "health and welfare objectives") or to impose substantive constraints not otherwise specified by CAA § 111(d). EPA's effort to give more meaning to the word "satisfactory" is inconsistent with the law and a misplaced effort to expand the Agency's authority under CAA § 111(d).

Lastly, EPA explains that when a state decides to establish a standard of performance based on consideration of remaining useful life and other factors, it must "determine and include, as part of the plan submission, a source-specific BSER for the designated facility" (87 FR 74821). EPA then prescribes criteria that the state must follow in determining BSER and setting a corresponding emissions standard. *Id*. This is the first time in this rulemaking (and, to our knowledge, the first time ever) that EPA has interpreted the statute as authorizing and requiring a state to conduct a BSER analysis under CAA § 111(d) rather than setting standards of performance based on an EPA BSER determination.

We agree with EPA that, when a state considers RULOF in setting emissions standards for a particular source or group of sources, it necessarily must conduct a BSER analysis as part of its analysis. When a state considers RULOF, EPA's own BSER analysis ceases to have meaning because fundamental elements of that analysis – such as the cost assessment and determination that a particular emissions control method is feasible or has been adequately demonstrated – cease to apply to the source(s) covered by the state RULOF analysis.

EPA asserts that "the statute requires the EPA to determine the BSER by considering control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating: (1) The cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology" and that "a state must also consider all these factors in applying RULOF for that source." *Id*. We agree that the statute requires the first three criteria to be considered in determining BSER. We agree that application of these criteria is consistent with the principle that state CAA § 111(d) plans must meet the statutory standard setting criteria. We do not agree that the statute specifies or requires that BSER also must be based on an assessment of "the amount of reductions" or "advancement of technology." A state has the discretion to consider these factors, but EPA cannot impose these factors on a state because the statute itself does not require that they be considered.

EPA goes on to assert that a state BSER analysis "must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG using the five criteria noted above." *Id*. We disagree. The state clearly must determine BSER based on the express statutory criteria. But the law does not require a state BSER analysis to "identify all control technologies available for the source," "use the same metrics," or provide an evaluation "in the same manner" as EPA used in developing its BSER analysis. These may represent EPA's preferred method of determining BSER, but nothing in the law requires a state to follow EPA's preferred method or authorizes EPA to reject a state standard that is based on a BSER determination that employs a different approach than EPA's.

12.7 EPA does not have authority to approve more stringent state programs that are based on consideration of remaining useful life and other factors.

In the original proposal, EPA offered an extensive explanation of why it now believes it has authority to approve state § 111(d) programs that are more stringent than would be required by application of the BSER determined by

EPA. That position is expanded in the Supplemental Proposal by EPA's assertion that "states may consider RULOF to include more stringent standards of performance in their state plans" (87 FR 74825). This position represents a complete reversal of the current Subpart B provision limiting application of "RULOF" to establishing less stringent measures (See 86 FR 63251).

EPA now asserts that the term "other factors" is ambiguous and that EPA "may reasonably interpret[] this phrase as authorizing states to consider other factors in exercising their discretion to apply a more stringent standard to a particular source" (87 FR 74825). Moreover, EPA now rejects the idea that the § 111(d) Subpart B variance provisions are relevant in interpreting the scope of the Agency's authority to approve more stringent standards based on consideration of RULOF. *Id*. EPA also rejects its prior analysis of the legislative history on the grounds that it provides no meaningful guidance to EPA. *Id*. at 74826. Lastly, EPA argues that its new interpretation is consistent with the purposes of CAA § 111(d) – i.e., "to require emission reductions from existing sources for certain pollutants that endanger public health or welfare." *Id*.

EPA's attempt to reverse its position here is misplaced and is not supported by the law. First, as we discuss above, the term "other factors" is not a carte blanche invitation from Congress for EPA to create whatever plausibly "reasonable" new authorities or constraints it might conceive. The term "other factors" must be interpreted in context. As EPA itself explains, the term "remaining useful life … is a factor that inherently suggests a less stringent standard." *Id*. In this context, it stands to reason that Congress intended the term "other factors" to be interpreted such that "other factors" are applied in the same way (to reduce rather than increase stringency). Because the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term "other factors" must be construed in this manner.

Second, EPA's position is grounded in its assertion that states are not required "to conduct a source-specific BSER analysis for purposes of applying a more stringent standard" because "[s]o long as the standard will achieve equivalent or better emission reductions than required by EG OOOOc, the EPA believes it is appropriate to defer to the state's discretion to, e.g., choose to impose more costly controls on an individual source." *Id*. at n. 273. At the same time, EPA correctly notes that "its authority is constrained to approving measures which comport with applicable statutory requirements." *Id*. at n. 274; see also *Id*. at 74813 (EPA may not approve and thereby "federalize" state programs that apply to pollutants and/or affected facilities not covered by Subpart OOOOc).

It is inconsistent and arbitrary for EPA to assert that a state must conduct a new source-specific BSER analysis if it wants to use RULOF to establish a less stringent standard than would be required under EPA's BSER determination (see *Id.* at 74821), while a state is not similarly constrained when establishing more stringent standards. EPA's assertion that a more stringent standard does not require a BSER analysis because it "will achieve equivalent or better emissions reductions than required by EG OOOOc" cannot be squared with the requirement that alternative state measures must "comport with applicable statutory requirements" – which in this case include the unambiguous requirement that BSER and corresponding emissions standards must be demonstrated in practice and cost effective. EPA's suggestion that it may defer to (and approve) more stringent state requirements simply because they are more stringent is wrong because that approach does not ensure that the more stringent standards meet the statutory standard-setting criteria.

12.8 The proposed well closure requirements are not needed as a practical matter and mostly beyond EPA's authority as a legal matter.

In the original proposal, EPA raised in concept the possibility of setting standards "to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged

ineffectively" (86 FR 63240). We explained in our comments that emissions from abandoned wells are not as great as EPA suggests and that issues related to well closure are more appropriately addressed by the states and BLM. We also explained that, if EPA decided to move ahead with such standards, the possibility of requiring a demonstration of financial capacity should not be a part of that proposed rule given EPA has no authority under the Clean Air Act to impose a financial assurance requirement.

In the Supplemental Proposal, EPA proposes regulations governing well closures in both NSPS OOOOb and EG OOOOc (87 FR 74736). The proposed rules closely track the concept outlined in the original proposal – including a requirement for developing and submitting a well closure plan within 30 days of the cessation of production from all wells at a well site, which must describe the steps that will be taken to close the well, proof of financial assurance, and a schedule for completing the closure. *Id*. Monitoring must be conducted after closure to demonstrate that there are no emissions from the closed well. *Id*. And changes in ownership must be reported on an annual basis during the life of a well. *Id*.

In light of this proposal, we reiterate our prior argument that the CAA does not grant EPA authority to impose financial assurance requirements.[101] We add that EPA did not respond to these comments in the Supplemental Proposal. We further note that EPA did not explain the legal basis for the proposed financial assurance requirements in either the original or Supplemental Proposal. Indeed, EPA cites no legal authority and provides no legal analysis for any aspect of the proposed well closure standards. Such an explanation is needed for such a key and novel aspect of this proposed rule so that interested parties have the opportunity to formulate and submit comments on EPA's legal rationale. CAA § 307(d)(3). The final rule will be procedurally deficient if EPA does not cure this problem.

Lastly, EPA provides little new evidence or arguments in the Supplemental Proposal as to why well closure standards are warranted. EPA appears to rely on the more extensive discussion provided in the original proposal. Notably, that discussion focuses on "abandoned wells" (i.e., "oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells") "that are not plugged or are plugged ineffectively." (86 FR 63240). The discussion particularly targets "orphan wells" – i.e., those that have been abandoned and for which "there is no responsible owner." *Id*. EPA explains that the proposed well closure standards constitute a "potential strateg[y] to reduce emissions from these sources." *Id*. at 63241.

EPA explains in passing that states and other federal government agencies regulate well closures and have programs to address abandoned and orphan wells. Yet EPA does not conduct an in-depth assessment of these programs or make any attempt to distinguish how much of the perceived problem with abandoned or orphan wells relates to wells that pre-date the current federal and state programs versus wells that are regulated by such programs. In other words, EPA asserts that well closure standards are needed to address the problem of emissions from abandoned or orphan wells but does not determine that current state and federal programs are somehow deficient and, therefore, need to be supplemented by EPA standards going forward.

If EPA had delved more deeply into the current state of affairs, it would have seen that industry, states, and other federal government agencies are making great progress in addressing abandoned and orphaned wells. For example, the federal Bureau of Land Management highlights on its website its extensive regulatory and non-regulatory efforts to address orphan wells, including the hundreds of millions of dollars allocated by Congress in

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[101] Comment 10.1.1 on page 40 in EPA-HQ-OAR-2021-0317-0808

the recent "Bipartisan Infrastructure Law" to support tribal, state, and federal efforts in this area. EPA does not even mention the Bipartisan Infrastructure Law in the original or Supplemental Proposals.

Before finalizing the proposed well closure standards, EPA needs to consider more closely the current regulatory landscape, the extensive non-regulatory measures focused on abandoned and orphaned wells, and the expansive voluntary efforts by industry to address this important issue. Those factors are critical to understanding whether EPA rules are needed and, if so, how they should be designed and implemented.

12.9 The Supplemental Proposal would impose unreasonable, impractical, and unduly burdensome certification requirements.

The applicability of several elements of the proposed rule depends on a certification of technical infeasibility that must be executed by a professional engineer or other qualified individual. Examples include the use of an emissions control device to handle associated gas (see, e.g., proposed § 60.5377b(b)(2)), the continued use of pneumatic pumps driven by natural gas (see, e.g., § 60.5393b(c)), and the use of emitting gas well unloading methods (see, e.g., §60.5376b(c)(2)(ii)(B)(2)). EPA imposes these certification requirements out of concern about the possible "abuse" of these provisions such that they might open a "loophole" in the regulations (87 FR 74776). EPA stresses that it, "wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties." *Id*. Thus, the proposal raises the serious prospect of individual, personal liability, not only for fraudulent certification, but also for technically erroneous (i.e., "significantly flawed") certifications.

As we discussed in our comments on the original proposal, we support these opt out provisions as a practical matter. We agree that non-emitting measures and methods should be used where they are technically feasible and cost effective. But EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. The proposed alternative measures are a common-sense solution.

But our comments on the original proposal also expressed the concern that EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating opt outs. We pointed out that the need to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA §111 because non-emitting standards are not "adequately demonstrated" if opt outs are needed to make them feasible and workable.

We reiterate those concerns about the legal basis for EPA's opt-out approach because onerous and potentially punitive certification requirements make the opt out approach even more legally tenuous. To begin, such certification requirements will significantly limit the situations where an opt out can be employed. As a result, what otherwise might be a reasonably viable alternative to an unworkable zero-emissions standard is unnecessarily complicated by strict certification requirements tied to an undefined standard that will be difficult to apply and limit the usefulness of the alternative. That heightens the concern that creating an opt out is unlawful circumvention of the obligation to demonstrate that BSER and the corresponding standards of performance are adequately demonstrated and cost effective.

Moreover, the proposed certification requirements are unreasonably onerous because, in each case, the certifying individual must essentially prove a negative – that the otherwise applicable zero-emissions approaches

are "technically infeasible." There is no definition of technical infeasibility in the proposed rules, but the words could be construed as setting an exceedingly high bar, such that a given non-emitting technique is "infeasible" based solely on a technical assessment of whether it can theoretically be physically applied in the given situation. So, for example, that might require a non-emitting technology to be applied because it is technically theoretically possible, even though it would be inordinately expensive. This outcome would not be lawful because it would violate the statutory requirement that BSER and the corresponding standard of performance must be cost effective.

And, in any event, a "technical infeasibility" standard allows for second guessing by regulators or citizen enforcers, which invites a "battle of the experts" in potential enforcement actions. All of this diminishes the possibility that the opts outs can be implemented with reasonable certainty.

Lastly, the express threat of possible personal liability on the part of certifiers surely will limit the number of individuals willing to make the needed certifications, particularly in light of the uncertainties described above about what will be needed as a practical matter to demonstrate "technical infeasibility." The clear opportunity and possibility of second guessing will be further material disincentives.

We provide here three recommended solutions to these problems. First, rather than creating opt outs that require case-specific certification, EPA should establish the opt outs in the final regulation as regulatory alternatives that may be employed if specified criteria in the rule are met. This is the usual method of prescribing standards of performance and regulatory compliance alternatives, and it would not be difficult for EPA to structure the rule in this fashion.

Second, as explained above, one of the legal flaws in EPA's opt-out scheme is that technical feasibility is the only governing criterion. The cost of implementing the default zero-emitting standard is not a consideration. As a result, the proposed opt-out approach unlawfully evades the obligation that cost must be considered in prescribing CAA § 111 standards of performance. This flaw is easily cured by including cost as a consideration in implementing the opt-out provisions.

Third, if EPA retains the requirement for case-specific certifications, EPA should revise the required certification. The proposed regulatory text of each certification includes the following sentence: "Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete." See, e.g., § 60.5377b(b)(2). This should be revised to specify that the certification is based on "reasonably inquiry," as is required for certifications under the Title V operating permit program. The revised certification could read as follows: "Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, …." A "reasonable inquiry" standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

12.10 EPA should not define and impose practical enforceability requirements without first developing a consistent approach for all EPA programs.

In the original proposal, EPA proposed "to include a definition for a 'legally and practicably enforceable limit' as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules" (86 FR 63201). EPA explained that "[t]he intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected

facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy." *Id*.

In our comments on that proposal, we urged EPA to defer final action on the proposed definition until such time as the Agency undertakes a broad-based rule that would provide a single, consistent approach across all affected CAA programs. Such an approach would prevent potential inconsistencies among the various CAA programs (e.g., an effective emissions limit used to avoid major New Source Review (NSR) permitting might, at the same time, not be effective for purposes of the OOOOb and/or EG OOOOc storage vessel standards); would avoid the possible implication that the "effectiveness" criteria established under EG OOOOc should be applied under other CAA programs (i.e., how can an emission limit be both effective and not effective at the same time), and allow EPA to establish reasonable transition rules so that affected sources and states have time to revise existing emissions limitations as needed to meet the new effectiveness criteria.

In addition, few existing sources have express emissions limitations for methane or GHGs. Yet, EPA has newly proposed a 20 tpy methane applicability trigger for the Subpart OOOOb and OOOOc storage vessel standards (in addition to the 6 tpy VOC trigger) (87 FR 74800). As a result, many potentially affected/designated facilities likely will seek to rely on VOC emissions limitations as a surrogate for methane emissions. The use of surrogates in establishing effective potential to emit (PTE) limits is another cross-cutting issue for which EPA should establish a unitary CAA approach rather than the proposed piecemeal, rule-by-rule approach.

We raise these issues again because EPA recently announced its intention to issue national guidance on establishing effective limits on potential to emit.[102] That effort appears to be driven by a July 2021 report from the EPA Inspector General that criticized the Office of Air and Radiation for not responding to a series of 1990's era D.C. Circuit decision that vacated or remanded the then "federal enforceability" criteria that applied across EPA's CAA regulatory programs.[103] EPA intends to issue national guidance by October 2023.

EPA's announced plan to establish national rules for effective limits on PTE and to do so in the relative near future lends strong additional support to our request that EPA should not address these issues in a premature and piecemeal fashion in the EG OOOOc rule.

13.0 Other General Comments

13.1 Due to the unreasonably short duration of the comment period for the Supplemental Proposal, API has been unable to respond to all of EPA's comment solicitations.

The proposed NSPS OOOOb and EG OOOOc are both complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, many stakeholders requested an extension of the comment period in order to provide the agency with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. Concurrent with this rulemaking there are additional and overlapping regulatory developments on this subject matter including the Inflation Reduction Act Methane Emissions Reduction Program, EPA's Redesignation of Portions of the Permian Basin for the 2015 Ozone

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[102] *NAAQS, Regional Haze & Permit Program Implementation Updates*, Presentation by Scott Mathias, Director Air Quality Policy Division, OAQPS, to AAPCA Fall Meeting (Sept. 29, 2022).

[103] *EPA Should Conduct More Oversight of Synthetic-Minor-Source Permitting to Assure Permits Adhere to EPA Guidance, Report No. 21-P-0175*, memorandum from Sean W. O'Donnell to Joseph Goffman (July 8, 2021) at 17.

National Ambient Air Quality Standards, EPA's Proposed Updates to the National Ambient Air Quality Standards for PM and the Bureau of Land Management's proposed Waste Prevention Rule that all must be reviewed in accordance with the overlapping aspects of these various actions.

To provide a complete set of comments on a rulemaking as broad, impactful, precedent setting, and complex as proposed within NSPS OOOOb and EG OOOOc, API requested an additional 60 days to gather information and submit comments. Not only did EPA decline API's and other stakeholders' reasonable request for a 60-day extension of the comment period, EPA did not grant even an additional two weeks as the Agency did for the initial proposal[104], which was smaller than the Supplemental Proposal. As we have stated in Comment 12.1*,* we recognize that every administration has the right to set and implement its regulatory agenda. Nevertheless, that this Administration would expedite issuance of the original proposed rule to align with COP26[105], delay issuance of the Supplemental Proposal to align with COP27[106], and then deny the request of pertinent stakeholders to have adequate time to provide fully-informed feedback to EPA, undermines this Administration's stated goals of reducing emissions in the service of political optics. API has developed as complete a set of comments provided herein as time has allowed. However, much of the information EPA requested, as well as additional information API wanted to provide, is not included herein due to the arbitrary and unnecessarily imposed timing constraints of the comment period for the Supplemental Proposal. We restate our industry's shared goal with EPA of reducing emissions from oil and natural gas operations across the value chain. We remain concerned that this Administration will rush to the completion of a final rule that is not cost-effective, technically feasible, or legally sound. We strongly encourage EPA to adopt the recommendations in our comments to enable the final rule to meet these critically important criteria.

13.2 EPA should reduce burden associated with the collective recordkeeping and reporting requirements.

Proposed NSPS OOOOb and EG OOOOc include onerous recordkeeping and reporting that exceed typical levels of compliance assurance and are a significant cost to operators to track and maintain. EPA should continue to focus on having operators track the most necessary information to obtain assurance.

In this proposal,

- EPA increased the recordkeeping and reporting requirements without adequately justifying increased costs with respect to the administrative burden these proposed changes would require, including numerous technical demonstrations and engineering statements. Increased costs associated with administrative burden are disproportional to benefit – because benefit is marginal when compared to other mechanisms that are already in place and proposed elsewhere in this rulemaking that focus on necessary information to assist in ensuring compliance.
- EPA continues to ignore the scale of affected/designated facilities that will become subject to these provisions over time, which is well over the tens of thousands.
- EPA has included reporting requirements that are outside the Agency's jurisdiction in requiring details on well ownership transfers.

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[104] https://www.federalregister.gov/documents/2021/12/17/2021-27312/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for
[105] https://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health
[106] https://www.epa.gov/newsreleases/biden-harris-administration-strengthens-proposal-cut-methane-pollution-protect

API recognizes that it is appropriate to maintain sufficient records to demonstrate compliance. However, it is API's view that it is excessive to require such a significant level of detail to be both documented and submitted for all of the affected/designated facilities in this proposal. EPA should simplify the recordkeeping and reporting requirements to those that assure compliance without additional administrative burden. Only elements needed for compliance assurance should be requested within the annual report as supporting records retained by companies can be made available upon request from the Agency.

API has provided some initial comments on certain recordkeeping and reporting aspects of proposed NSPS OOOOb and EG OOOOc throughout this comment letter, but due to the short comment period have not had adequate time to fully assess the impact of what EPA has proposed. Some initial thoughts on the proposed draft reporting form template include the following:

- One initial concern is that many companies do not allow the use of workbooks containing macros as a cybersecurity measure and the current draft workbook contains macros. If the form is dependent on the macro formatting, this may be an issue for some reporters using the form.
- We do not support the reporting of additional information related to well transfers (including name, phone number, email, and mailing address) as proposed §60.5420b(b)(1)(v).
- The control device and closed vent system tabs are set up where multiple affected facilities that route to a single control device or through the same closed vent system cannot be identified on a single row. This will result in redundant and duplicate information being reported.
- Certain selection options for “Deviation Category” the “Description of Deviation” and “Type of Deviation” cells are automatically blacked out and do not allow an operator to provide additional context. The operator should have the ability to add free text in these areas and provide additional information as needed.

We will continue to review the recordkeeping and reporting requirements proposed within these rules along with the draft reporting form (EPA-HQ-OAR-2021-0317-1536_content) and continue to provide EPA feedback on ways to streamline the template.

13.2.1 CEDRI System Concerns

Our members have concerns with the practical implications with reporting through CEDRI when/if there is a system outage. Specifically, we request EPA evaluate the following language as proposed under NSPS OOOOb and EG OOOOc, but note these concerns also apply to NSPS OOOOa:

- §60.5420b(e)(2): We believe this paragraph should be removed or, at a minimum, be inclusive of the compliance end period and the compliance submittal date. Staff scheduling submittal may choose to do so prior to 5 days before the compliance submittal date. If EPA is requiring the use of the reporting form within CEDRI, then it should not be in deviation on the operator in any circumstance.

- §60.5420b(e)(4): The requirement for the reporter to notify EPA immediately upon discovery of an outage is unduly burdensome for the reporter. EPA should manage the reporting system and notify registered users of an outage.

- §60.5420b(e)(5)(iii): It is unclear what EPA is intending for a reporter to include as far as “a description of measure taken to minimize the delay in reporting”. EPA should be taking action to minimize the delay in reporting if there is a CEDRI system outage. The regulated entity has no additional recourse in this instance.

- §60.5420b(e)(6): System outage should warrant automatic claims to those submitting reports. Operators should not be penalized when the only method for submittal is not available and out of their control.

- EPA should implement a secure process, similar to EPA's e-GGRT program, to prevent those who are not owners or operators or are authorized representatives of an affected facility from submitting to CEDRI for any affected facility.

13.3 EPA should clarify its statements regarding the Crude Oil and Natural Gas source category and the extent of crude oil operations for purposes of this rulemaking.

Within proposed NSPS OOOOb and EG OOOOc the Crude Oil and Natural Gas source category is defined consistent with historical definitions finalized in NSPS OOOO and NSPS OOOOa:

> *Crude oil and natural gas source category means:*
>
> *(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and*
> *(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.*

In footnote 301 (87 FR 74833), EPA states:

> 301 "*For purposes of the November 2021 proposal and this supplemental proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.*

We do not believe that EPA intends to regulate crude oil operations beyond the point of custody transfer from a well to a transmission pipeline and we request that EPA clarify and correct these statements in the final rule to align with the definition of the source category as proposed.

13.4 Applicability for Inactive sites and Reactivation of Inactive Sites

Many sites may periodically shut-in or depressurize all or partial equipment, where the entire site might be inactive or certain equipment might be inactive. We believe this is an appropriate criterion for exemption for all affected or designated facilities under NSPS OOOOb and EG OOOOc. At a minimum, we seek clarification as the status of inactive facilities and depressurized equipment as they pertain specifically to fugitive emission monitoring (Comment 2.5) and the retrofit of pneumatic controller and pneumatic pump provisions under EG OOOOc. We do not believe it is EPA's intent to require facilities that are not in active operations to retrofit the pneumatic controllers at the facility to non-emitting nor would it be appropriate for equipment that has been depressurized and inactive to be screened for fugitive emission monitoring.

Additionally, some inactive sites or equipment might be put back into service, where the applicability under NSPS OOOOb versus EG OOOOc must be delineated. One example is under *Pennsylvania's § 127.11a. Reactivation of sources*, which allows: *"a source which has been out of operation or production for at least 1 year but less than or equal to 5 years may be reactivated and will not be considered a new source if the following conditions are satisfied…".* EPA already has included language addressing this concept as it pertains to storage vessels. We

believe EPA should extend this concept to all affected and designated facilities. If a site that was inactive were to become active, there should be adequate time for the site to comply with the provisions within EG OOOOc.

13.5 The Social Cost of Greenhouse Gases

API shares the Administration's goal of reducing economy wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the EPA's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

In Attachment B, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine provided to the IWG.

13.6 Cross Reference and other Minor Clarifications

Below are some cross reference and other typos we have identified within the prosed NSPS OOOOb and EG OOOOc regulatory text.

- Subpart OOOOc makes eight references to a §60.5933c, one of which gives its title as "Alternative Means of Emissions Limitation." However, there is no actual section in EG OOOOc with that number or title.
- §60.5413b(d)(11)(iii): *A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC and methane (if applicable) required under this subpart.*
- §60.5370b(a)(1)(iii) refers to §60.5385b(a)(3), which does not appear to exist.
- The additional citations should be checked for correct cross referencing: §60.5420b(c)(2)(ii)(B), §60.5410b(f)(2)(iv)(B), §60.5420b(b)(10)(vi), and §60.5420b(c)(12).

Attachment A

Responses to EPA Solicited Comments for Use of Optical Gas Imaging in Leak Detection

Responses to EPA Solicited Comments for Use of Optical Gas Imaging (OGI) in Leak Detection

VI.C OGI Monitoring Requirements – Specifying Dwell Time to Account for Scene Complexity

[T]he EPA is soliciting comment on how dwell time could be based on the scene while still accounting for the differences in the complexity of scenes or ways to create bins for “simple” and “complex” scenes.

Response: *The most intuitive method to differentiate between “simple” and “complex” scenes would be to base it on the number of components being imaged and viewing distance. An example of a “simple” scene would be a scene of 20-25 components viewed at a distance of < 15-25 feet. This approach offers a high probability of leak detection by a technician. The high probability of detection is supported by existing operating envelope testing conducted by camera manufacturers which demonstrated consistent image detection at these distances at delta-T as low as 2 degrees C. Moreover, the number of components being limited to 25 in a simple scene means a technician is likely to have great discernment or granularity of the image which improves their ability to detect image of a leak. “Complex” scenes would be when there are greater than 25 components or viewing distances greater than 25 feet.*

VI.C OGI Monitoring Requirements – Ensuring OGI Camera Operators Survey a Scene is Adequate Without Specifying Dwell Time

The EPA is also soliciting comment on ways to similarly achieve the goal of ensuring that OGI camera operators survey a scene for an adequate amount of time to ensure there are no leaks from any components in the field of view without specifying a dwell time.

Response: *The “simple” scene criteria offered previously ensures that a technician has optimum image detection consistent with operating envelopes of camera. Specifying a dwell time for these types of scenes would be irrelevant as the technician will be looking closely at the scene in their viewfinder looking to detect any imagery. Placing a constraint of dwell time would complicate their efforts and distract from their efforts at viewing the scene. A well-trained technician who consistently passes their performance audits will be expected to make a diligent and careful survey of the components in the scene.*

VI.C OGI Camera Operators – Performance Audit Frequency

The EPA believes that it is important to verify the performance of all OGI camera operators, even the most experienced operators, on an ongoing basis. Nevertheless, the EPA is requesting comment on whether there should be a reduced performance audit frequency for certain OGI camera operators, and if so, who should qualify for a reduced frequency, what the reduced frequency should be, and the basis for the reduced frequency.

Response: *The performance audit requirements can become a significant time-consuming activity for site(s) with large numbers of technicians in their survey crew. In the initial stages of OGI monitoring implementation, more frequent performance audits have a key role to play in ensuring technician efficacy. However, technician monitoring proficiency will increase quickly over time as their monitoring experience and time doing surveys increases. The*

agency's reference to the MTEC study clearly documented this to be the case. As such, for technicians who consistently have satisfactory performance audits, it is appropriate to extend the interval between audits for those technicians. A simple methodology to do so is to follow a "skip period" approach to performance audits. For technicians who pass four consecutive quarterly performance audits, then their audit interval should be extended to semi-annual. For technicians who pass two consecutive semi-annual performance audits, then their audit interval should be extended to annual. If a technician does not pass a semi-annual or annual audit or conduct a monitoring survey during the previous 12 months per Section 10.5 of Appendix K, then quarterly performance audits would be restarted.

VI.C OGI Surveys – Length of Survey Period

[T]he EPA has heard anecdotally that this may have more to do with the number of hours the OGI camera operator has surveyed during the day, such that it is more appropriate to limit the hours of surveying per day than it is to mandate rest breaks at a set frequency. The EPA is seeking any empirical data on the topic of the necessity of rest breaks when conducting OGI surveys or the link between operator performance and length of survey period.

***Response**: Fatigue potential is directly related to duration of continuous viewing through the camera and holding the camera in viewing position for extended periods. OSHA already has appropriate guidelines for ergonomics in the work place which include eye strain etc. Sites already have rigorous guidelines and safeguards for ergonomics, heat stress, etc. EPA should not attempt to develop regulatory standards for technician rest breaks. The agency should simply state that the monitoring plan incorporate appropriate rest breaks for technicians and simply state a rest break is required if the technician has been conducting a continuous viewing through OGI camera for 20 minutes or more. It is important to note that technicians would rarely have a 20-minute continuous viewing scenario. The primary monitoring method is to survey a component or scene for 1-2 minutes and then move to next location. When moving viewing locations, the technician would lower the camera to a neutral position and not be "viewing" though camera.*

VI.C Adequate Delta-T – OGI Camera

The EPA is proposing that the monitoring plan must describe how the operator will ensure an adequate delta-T is present to view potential gaseous emissions, e.g., using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view. […] [A] commenter stated guidance should be added for operators who are using a background temperature reading in the OGI camera field of view. The EPA is requesting comment on ways that an OGI camera operator can ensure an adequate delta-T exists during monitoring surveys for cameras that do not have a built-in delta-T check function.

***Response:** The simplest and most straightforward way for a technician to ensure adequate delta-T is to utilize the camera's function to display the temperature of the equipment or background behind the component being surveyed for leaks. Most, if not all, OGI cameras in use for leak surveys have this ability currently. As such, if the technician knows the ambient temperature, then it is a simple step to add/subtract the background from ambient to determine delta-T. The elegance of this approach is it allows the technician to adjust their angles or take additional steps in*

real-time during the survey process to ensure the delta-T of the operating envelope is maintained during any survey step.

VI.C Daily OGI Camera Demonstration Prior to Imaging to Determine Maximum Distance for Imaging

[O]ne commenter suggested that instead of having different operating envelopes for different situations and having to decide which envelope to use, the OGI camera operator should conduct a daily camera demonstration each day prior to imaging to determine the maximum distance at which the OGI camera operator should image for that day. The EPA believes that this type of determination would be more difficult and costly than creating an operating envelope, as it would require OGI camera operators to have necessary gas supplies on hand and take time to do this determination daily, or potentially multiple times a day. Nevertheless, the EPA is requesting comment on this suggestion, as well as how such a demonstration could be used if conditions on the site change throughout the day, at what point would the changed conditions necessitate repeating the demonstration, and how changes in the background in different areas of the site (such as to affect the delta-T) would be factored into such a demonstration.

Response: *Use of pre-defined operating envelopes through testing as prescribed in Section 8.0 of Appendix K is a highly useful and pragmatic methodology to determine detection capability and restrictions for monitoring surveys. It is expected that most OGI camera manufacturers plan to have completed the development of the operating envelopes after Appendix K is promulgated. However, the option for a site to do a daily or site-specific distance check utilizing a known gas concentration and flow rate at actual metrological conditions prior to conducting monitoring surveys should remain an option for a site.*

The reasons for retaining an option for a daily distance check are two-fold. First, a site may be conducting monitoring surveys with an OGI camera that does not yet have established operating envelopes. This could occur for a site using an OGI camera new to market or simply that initial monitoring surveys are planned to improve emissions reductions potential prior to the manufacturer publishing operating envelopes. Second, a site may believe that monitoring conditions for a given survey or site are unique with respect to pre-defined operating envelopes and want to ensure that the guidance on delta T and distance are appropriately set for the technicians' survey task. It is logical to include this option in Appendix K.

With respect to changing conditions, technicians should already be trained in recognition of factors (e.g., meteorological conditions) which would impact the leak detection capability. When conditions are significantly different then the technicians should switch to another operating envelope or conduct another distance check verification. This is already adequately addressed in Section 9.2.3. language.

Comments for Appendix K

"Appendix K. The EPA is not including a requirement to conduct OGI monitoring according to the proposed appendix K for well sites or centralized production facilities, as was proposed in the November 2021 proposal. Instead, the EPA is proposing to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21." [FR74723]

Comment: *This is the correct decision and recognizes the fundamental differences between upstream production and other industry sectors.*

Definition of fugitive emissions component. The EPA is proposing specific revisions to the definition of fugitive emissions component that was included in the November 2021 proposal. First, the EPA is proposing to add yard piping as one of the specifically enumerated components in the definition of a fugitive emissions component. While not common, pipes can experience cracks or holes, which can lead to fugitive emissions. The EPA is proposing to include yard piping in the definition of fugitive emissions component to ensure that when fugitive emissions are found from the pipe itself the necessary repairs are completed accordingly. [FR 74723]

Comment*:* *Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.*

Definition of fugitive emissions component. Based on changes made and discussed under section IV.A.1.a.ii of this preamble, the EPA is proposing to define fugitive emissions component as any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and CVS not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping. [FR 74736]

Comment*:* *The agency has consistently set VOC and VHAP content criteria in all previous fugitive emissions component monitoring requirements. These thresholds were typically defined as "in VOC service" which specified 10% VOC as the appropriate level where the emission reduction potential from leaking components was cost-beneficial. The agency stated that no data had been offered to support a one percent methane threshold and that produced water and wastewater streams can be significant sources of emissions. In the cited reference document ''Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations.'' Final Report. California Air Resources Board. May 2020, it stated that concentrations of compounds in the liquid phase were the best prediction of expected air emissions. This is correct and makes the point of industry comment to set a definitive threshold where cost beneficial emissions can be expected. Emissions potential is directly related to the concentration of methane and/or hydrocarbon in the process stream. Small concentrations of VOC (<10 wt%) and methane do not represent significant emissions potential; a fact that the agency has recognized in multiple updates to fugitive emission regulations.*

The apparent agency approach was simply to set the threshold at a single molecule which is inconsistent with decades of regulatory approaches to fugitive emission control methodology. As the relative proportion of VOC or methane in the given component goes down, the cost effectiveness of LDAR gets increasingly less favorable until, when the amount of VOC or methane approaches zero, the cost effectiveness value approaches infinity. The agency must consider cost for BSER determination. The content threshold used within the agency's cost effectiveness analysis is unclear. Either the agency used the traditional threshold content approach for estimating the potential regulated component inventory or it has overstated the cost effectiveness through the overstatement of emissions potential from components with very small methane and VOC contents.

In the preamble, the agency stated that industry had offered no empirical data to not establish an appropriate threshold. The agency has not demonstrated why a 1% methane and 10% VOC threshold are not appropriate, or how meaningful and cost-effective emission reductions are achieved at levels below those proposed by industry. This demonstration was not met by the agency in their definition of "potential to emit" and therefore the agency has not justified their decision. The recommendation to set the definition to include the VOC threshold at 10% and methane at 1% is an appropriate good faith effort by industry to reduce emissions.

EPA proposed that where a CVS is used to route emissions from an affected facility, the owner or operator would demonstrate there are no detectable emissions (NDE) from the covers and CVS through OGI or EPA Method 21 monitoring conducted during the fugitive emissions survey. Where emissions are detected, the emissions would be considered a violation of the NDE standard and thus a deviation. [FR 74804]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. These standards mandate that closed-vent systems are monitored annually with 5/15-day repair criteria. Routine AVO monitoring rounds by unit operators is also a standard work practice. CVS piping and components have been consistently found to have low leak percentages which makes sense when one considers that most of these components remained in a fixed configuration (i.e.., car-sealed open) and there is little to no operating changes of the FECs.*

The agency proposed action to make any emissions detection a violation is also a departure from historical leak detection and repair regulatory standards. EPA stated that their logic was that the NDE requirement was an emission standard and as such it has to be a violation even if repair provisions were allowed. This is an inappropriate regulatory approach since the NDE requirement should be considered a work practice standard rather than a numerical emissions standard. The CVS and control device requirements are sufficient to ensure that NDE operating conditions are the norm. The fact that the agency has prescribed monitoring survey requirements indicates the agency knows this paradigm to be true. The most important aspect of leak detection is routine surveillance of components and piping at appropriate intervals with prompt repair to stop the leak. The current 5-15 day repair timelines achieves this fundamental precept of LDAR, and making any leak detection a violation is an unnecessary addition to the requirements that does not expedite repairs or provide environmental benefits. Violations occur when repairs are not completed per requirements and/or routine monitoring is not conducted on-time or efficaciously.

In addition to this bimonthly OGI monitoring requirement, the EPA is also proposing to require OGI monitoring of each pressure relief device after each pressure release, as it is important to ensure the pressure relief device has reseated and is not allowing emissions to vent to the atmosphere. The EPA is soliciting comment on this change from a no detectable emissions standard to a bimonthly monitoring requirement. Where the EPA Method 21 option is used, we are proposing quarterly monitoring of the pressure relief device in addition of monitoring after each pressure relief. A leak is defined as an instrument reading of 500 ppm or greater when using EPA Method 21. [FR 74807]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. The most recent and stringent precedent for PRDs is found in the Part 63 Subpart CC which*

requires monitoring post-release to verify re-seating of PRD. The agency has consistently followed this approach in other RTR evaluations which makes this approach inconsistent with agency's technical analysis.

Not requiring routine monitoring of PRDs makes sense if one considers that if PRDs are properly seated then they are assumed to be in non-venting condition. Monitoring post-release is sufficient to ensure the emission standard is maintained.

EPA is proposing a requirement to monitor the CVS at the same frequency (i.e., bimonthly OGI in accordance with appendix K or quarterly EPA Method 21) as other equipment in the process unit and to repair any leaks identified during the routine monitoring. [FR 74808]

Comment: *In existing and recently revised NSPS and NESHAP standards for closed vent systems and control devices, the agency has prescribed initial inspection and on-going annual AVO inspections. The agency indicated there would be no cost to do these surveys, but that is incorrect. The monitoring survey routes would have to be expanded to include the CVS piping/ductwork sections which increases labor costs based on increased technician field survey time.*

Appendix K

EPA is proposing to revise the scope and applicability for appendix K to remove the sector applicability and to base the applicability on being able to image most of the compounds in the gaseous emissions from the process equipment. The EPA is retaining the requirement that appendix K does not on its own apply to anyone but must be referenced by a subpart before it would apply. [FR 74837] (App K VI.B.1)

1.3 Applicability. This protocol is applicable to facilities when specified in a referencing subpart. This protocol is intended to help determine the presence and location of leaks and is not currently applicable for use in direct emission rate measurements from sources

Comment: *This change in applicability is the correct approach. However, consistent with previously submitted comments on the proposed rulemaking, we recommend EPA proceed expeditiously to amend part 63 subpart CC (RMACT 1) to allow use of OGI technology and Appendix K as an alternative to Method 21 for refineries. In the recent Refinery Sector Rulemaking, EPA proposed allowing for use of OGI as an alternative to Method 21, but did not finalize that proposal because "we have not yet proposed appendix K."*[107] *Adding OGI as an alternative to RMACT 1 would significantly reduce the refinery and Agency resources associated with preparing and reviewing Alternative Method of Emission Limitation or Alternative Monitoring requests to allow OGI for those facilities and allow refineries to take advantage of the improvements inherent in Appendix K versus the currently available leak detection and repair (LDAR) Alternative Work Practice (AWP) in Part 60 Subpart A (§60.18(g), (h) and (i)). Moreover, it would be important for EPA to amend other Part 60 and 63 standards to make Appendix K an option for industry sectors beyond refineries.*

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[107] 80 *Fed. Reg.* 75191 (December 1, 2015)

6.1.2 The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr) and either butane emissions of 5.0 g/hr or propane emissions of 18 g/hr at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less, unless the referencing subpart provides detection rates for a different compound(s) for that subpart.

Comment: *The response factor for butane and propane are almost identical, why has the agency selected lower mass rate criteria for butane? It seems inconsistent with the language in Section 1.2 which allows for the average response factor approach with respect to propane.*

9.3 The site must conduct monitoring surveys using a methodology that ensures that all the components regulated by the referencing subpart within the unit or area are monitored. This must be achieved using one of the following three approaches or a combination of these approaches. The approach(es) chosen and how the approach(es) will be implemented must be described in the monitoring plan

Comment: *The language provided in the Appendix K revisions for monitoring survey methodology provides additional flexibility consistent with industry comments. However, as written, the methodology is limited to just three options without any ability for a site to propose an alternative. Technology and survey approaches are always being improved with new creative ideas coming to forefront all the time. For example, use of GPS in surveys is only a recent capability in the past few years. The agency should add language which allows a site to use another methodology as long as it meets the intent and capabilities of the ones currently identified. A site could propose an alternative to their delegated authority prior to use*

9.4.1 For a complex scene of components, the operator must divide the scene into manageable subsections and dwell on each angle for a minimum of 2 seconds per component in the field of view (e.g., for a subsection with 5 components, the minimum dwell time would be 10 seconds). It may be necessary to reduce distance or change angles in order to reduce the number of components in the field of view

Comment: *See comments provided on "simple" and "complex" scene approaches.*

9.7.2 A full video of the monitoring survey must be recorded. The video must document the monitoring results for each piece of regulated equipment. Leaking components must be tagged for repair, and the date, time, location of each leak, and identification of the component associated with each leak must be recorded and stored with the OGI survey records.

Comment *– This language could be read to imply a full continuous video of the monitoring survey would be required which is inconsistent with the language of Section 9.7.1 where only video or still imagery of the leaks are required. This language should be deleted or clearly state that sites may elect as alternative to simply save the full continuous video versus leak imagery only.*

9.8 The monitoring plan must include a quality assurance (QA) verification video for each OGI operator at least once each monitoring day. The QA verification video must be a minimum of 5 minutes long and document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration.

***Comment** – As mentioned in previous comments to Appendix K proposals, the daily QA verification video is unlikely to offer much value to a monitoring program. The most effective methodology to ensure technician monitoring efficacy is comparative monitoring via periodic performance audits. The daily quality assurance (QA) verification video requirement should be deleted.*

10.2.2.1 A minimum of 3 survey hours with OGI where trainees observe the techniques and methods of a senior OGI camera operator (see definition in Section 3.0) who reinforces the classroom training elements.

10.2.2.2 A minimum of 12 survey hours with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and providing instruction/correction where necessary.

10.2.2.3 A minimum of 15 survey hours with OGI where the trainee performs monitoring surveys independently with a senior OGI camera operator trainer present and the senior OGI camera operator providing oversight and instruction/correction to the trainee where necessary.

***Comment:** The specific hourly requirement for each survey training phase is too restrictive and does not reflect how individuals learn and master new skills. Some technicians may need more or less time in a particular phase or benefit more from side-by-side or direct observation. A more appropriate approach is to specify a total of 30 hours of field survey hours which includes direct observation, side-by-side, and independent surveys without such prescriptive hourly content. As long as the 30 hours of training surveys includes an appropriate number of components to be surveyed (e.g., 300) and a final monitoring survey test, then the proficiency will be attained and verified.*

Attachment B

Comments on the U.S. Environmental Protection Agency's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

I. INTRODUCTION

As an addendum to our comments on the U.S. Environmental Protection Agency's ("EPA's" or "the Agency's") Supplemental Notice of Proposed Rulemaking on the revised "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" ("Proposed NSPS Revision"),[108] the American Petroleum Institute ("API") respectfully submits these additional comments on EPA's "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances" ("SC-GHG Report").[109]

API represents all segments of America's oil and natural gas industry. Our over 600 members produce, process, and distribute the majority of the nation's energy. The industry supports millions of U.S. jobs and is backed by a growing grassroots movement of millions of Americans. API was formed in 1919 as a standards-setting organization. In our first 100 years, API has developed more than 700 standards to enhance operational and environmental safety, efficiency, and sustainability. API and its members are committed to delivering solutions that reduce the risks of climate change while meeting society's growing energy needs. Addressing this dual challenge requires new approaches, new partners, new policies, and continuous innovation.

API believes that the pace of global action to reduce greenhouse gas ("GHG") emissions and effectively mitigate climate change will be determined by government policies and technology innovation. To that end, we have laid out a Climate Action Framework[110] that presents actions we are taking to accelerate technology and innovation, further mitigate GHG emissions from operations, advance cleaner fuels, drive comparable and reliable climate reporting, and, importantly, endorse a carbon price policy.

The natural gas and oil industry is essential to supporting a modern standard of living for all by ensuring that communities have access to affordable, reliable, and cleaner energy, and we are committed to working with local communities and policymakers to promote these principles across the energy sector. Our top priority remains public health and safety, and companies often have well-established policies in place for proactive community engagement and feedback aimed at fostering a culture of trust, inclusivity, and transparency. We believe that all people should be treated fairly, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

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[108] 87 Fed. Reg. 74,702 (Dec. 6, 2022).
[109] Docket ID No. EPA-HQ-OAR-2021-0317 (Sept. 2022).
[110] https://www.api.org/climate.

Indeed, API has for many years attempted to constructively engage the IWG in its development of SC-GHG estimates, and has submitted detailed comments on multiple previous IWG technical support documents, including the IWG's most recent "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" ("Interim TSD").[111] Those comments provided the IWG constructive and actionable recommendations to improve the transparency, rationality, defensibility, and thus, durability of its estimates of the SC-GHG, and urged caution on the inherently limited utility of SC-GHG estimates. Those comments also specifically recommended that the IWG publish proposals for, and accept public comment on, the recommendations the IWG was required to provide by September 1, 2021 regarding potential applications for the SC-GHG,[112] the additional recommendations the IWG was required to provide by June 1, 2022 for revising the processes and methodologies for estimating the SC-GHG,[113] and final SC-GHG estimates the IWG was supposed to publish "no later than January 2022."[114]

Insofar as API is aware, after publishing the interim SC-GHG estimates in 2021, the IWG has not completed any of the actions required by E.O. 13990 or taken any action in response to comments and recommendations submitted by API and other parties. Moreover, notwithstanding that EPA is a key participant in the IWG, EPA's unilateral development of the revised SC-GHG estimates in the SC-GHG Report is not only inconsistent with the approach President Biden committed to in E.O. 13990, it does not appear to reflect any consideration of the comments API and others provided to the IWG.

In the detailed comments that follow, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine ("National Academies" or "NASEM") provided to the IWG.

Although API appreciates EPA's willingness to accept comments on the SC-GHG Report, consistent with the National Academies' recommendations, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each modules had been updated and the SC-GHG Report had been fully drafted. Given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is insufficient for soliciting detailed feedback from informed stakeholders, particularly given that this comment period encompassed multiple holidays.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. This is a particular concern in a rulemaking conducted pursuant

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[111] 86 Fed. Reg. 24,669 (May 7, 2021).

[112] *See* 86 Fed. Reg. at 24,670.

[113] *See* E.O. 13990 at Sec. (5)(b)(ii)(D) and (E).

[114] *See* E.O. 13990 at Sec. (5)(b)(ii)(B).

to the Clean Air Act ("CAA" or "the Act") because of the CAA's enhanced requirement that EPA justify rules based solely on the record it compiles and makes public at the time of the proposal.[115]

Notwithstanding the forgoing, in Section III.b. below, API raises a number of significant technical questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. As noted therein, it is critical the SC-GHG Report completely and transparently explain the precise basis for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Finally, in Section III.c, API describes why, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. As EPA seemingly recognizes based on its apparent intent to use the SC-GHG Report in the Regulatory Impact Analysis but not as part of its assessment of the Best System of Emissions Reduction ("BSER") in the Proposed NSPS Revision itself, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.[116]

II. BACKGROUND

As noted in EPA's SC-GHG Report, the SC-GHG represents "the monetary value of future stream of net damages associated with adding one ton of that GHG to the atmosphere in a given year."[117] This metric, which originally attempted to estimate the social cost of only CO_2 emissions, "was explicitly designed for agency use pursuant to E.O. 12866. . ."[118] Since it was signed by President Clinton in 1993, E.O. 12866 has directed agencies to "propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs."[119] And when the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). Thus, the SC-GHG Report characterizes the SC-GHG as "the theoretically appropriate value to use when conducting benefit-cost analyses of policies that affect GHG emissions,"[120] and consistent with that characterization, EPA purports to only rely on the SC-GHG Report in the RIA it issued in support of the Proposed NSPS Revisions.[121]

Initially, federal agencies' consideration of CO_2 emissions in RIAs was sporadic and varied significantly between agencies.[122] When agencies did consider CO_2 emissions, they utilized a variety of different methodologies that

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[115] *See Sierra Club v. Costle*, 657 F.2d 298, 401 (D.C. Cir. 1981).

[116] *See* 87 Fed. Reg. at 74,713.

[117] SC-GHG Report at 4.

[118] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428. Per E.O. 12866 Sec. 1(a): "Federal agencies should promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling public need, such as material failures of private markets to protect or improve the health and safety of the public, the environment, or the well-being of the American people. . . . Further, in choosing among alternative regulatory approaches, agencies should select those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach."

[119] E.O. 12866 at Sec. 1(a). When the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). (E.O. 12866 at Sec. 6(a)(3)(C)). A "Significant regulatory action" is "any regulatory action that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in [E.O. 12866]" (Sec. 3(f)).

[120] SC-GHG Report at 4.

[121] *See* 87 Fed. Reg. at 74,713.

[122] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

resulted in a wide range of estimates, each with different ranges of uncertainty.[123] The government was consistent, however, in limiting use of these early estimates to RIAs, and in providing separate values for "domestic" and "global" impacts.[124] The government's consideration of CO_2 emissions became more frequent and consistent, however, after a 2008 Ninth Circuit decision remanded a fuel economy rule for failing to consider the potential benefit of CO_2 emission reductions, stating that "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero."[125] Subsequent court decisions on the necessity and method of considering CO_2 emissions for federal agency actions have been mixed.

To help federal agencies comply with E.O. 12866, "harmonize a range of different SC-CO_2 values being used across multiple Federal agencies,"[126] and "ensure consistency in how benefits are evaluated across agencies," President Obama established the IWG in 2009.[127] The IWG was tasked with developing "a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions."[128] As such, from the beginning, the IWG's SC-GHG estimates were intended to provide consistency across federal government agencies exclusively for the development of RIAs for "significant regulatory actions" involving GHG emissions. Notably, [t]his does not apply to many routine agency actions that will produce GHG emissions."[129]

The IWG's November 2013 TSD represented the first time the IWG (through OMB) accepted comment on the SC-CO_2 estimates.[130] Although the IWG and OMB had finally agreed to accept comments, they did not provide any materials other than the most recent TSDs. Thus, comments submitted by API and others urged the IWG to select its Integrated Assessment Model ("IAM") parameters through a highly transparent, collaborative, and data-driven process because modest changes to just a few model inputs drastically changes the output of the IAMs and therefore the SC-CO_2 estimate.[131]

The IWG broadly responded to the comments it received on the 2013 TSD in July 2015.[132] In that response, the IWG reiterated that the "purpose of [the IWG's] process was to ensure that agencies were using the best available information and to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions, or costs from increasing emissions, in regulatory impact analyses."[133]

The IWG updated its estimates of the SC-CO_2 again in August of 2016[134], and while API and others continued to have concerns with the transparency and rigor with which the IWG selected its model inputs, the TSD for the 2016 SC-CO_2 reflected some improvement to the characterization of uncertainty that was consistent with the NASEM Phase

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[123] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[124] Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (February 2020) ("2010 TSD) at 3.

[125] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin*., 538 F.3d 1172, 1200 (9th Cir. 2008).

[126] 2021 TSD at 10.

[127] 2010 TSD at 4.

[128] 2010 TSD at 5.

[129] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[130] OMB's first-ever solicitation of public comment on the SC-CO_2 estimates was likely in response to a September 4, 2013 multi-association Petition for Correction filed under the Information Quality Act ("IQA") and numerous demands from Congress and other stakeholders for increasing the transparency of the SC-CO_2 estimation process.

[131] *See* multi-association comments filed February 26, 2014 (OMB-2013-0007-0140). OMB's July 2015 Response to Comments did not provide the key information sought by API and others, and resisted recommendations that the IWG select these parameters through a transparent process subject to peer review. (*See* July 2015 Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.) To its credit, however, OMB requested feedback from the NASEM on the IWG's process for updating the estimates of the SC-CO_2. (*See* NASEM 2017 at 1).

[132] Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (July 2015) ("2015 RTC").

[133] 2015 RTC at 3.

[134] 2016a TSD.

1 Report,[135] as well as API's prior comments. Notably, in an addendum to the 2016 TSD, the IWG adapted its SC-CO_2 methodology to estimate social costs for methane and nitrous oxide for the first time.[136] While the 2016 TSD represented the first time the IWG provided estimates of non-CO_2 GHG emissions, the IWG continued to represent that the purpose of the estimates was to allow agencies to consistently "incorporate the social benefits of reducing . . . emissions into cost-benefit analyses of regulatory actions."[137]

Months later, President Trump disbanded the IWG and instead directed each agency to develop their own SC-GHG estimates using the same IAMs and the IWG's same overall methodology for estimating the SC-GHGs.[138] As the U.S. Department of Justice explained in its June 4, 2021 brief in opposition to several states' motion to preliminarily enjoin Section 5 of E.O. 13990, and the interim SC-GHG values published under E.O. 13990:

> Although the Trump Administration's policy approach to climate issues differed in many ways from that of the preceding administration, it continued to use standardized estimates of the social costs of greenhouse gases. Pursuant to E.O. 13783, EPA developed interim SC-CO_2 estimates by making two (*and only two*) changes to the Working Group's 2016 estimates: First, it began reporting estimates that attempted to capture only the domestic impacts of climate change, and second, it applied 3% and 7% discount rates. . . . Accordingly, although the Working Group had been disbanded, and although the estimates of the social costs of greenhouse gas estimates were now lower (because of higher discount rates and an exclusive focus on U.S.-domestic damages), agencies continued to estimate the social costs of greenhouse gases in their cost-benefit analyses, as ordered by the President, just as they had done in prior administrations.[139]

While these two changes[140] were seemingly modest, their impact on the SC-GHG estimates, was anything but small. When the Obama Administration conducted its RIA for the Clean Power Plan ("CPP") in 2015, it estimated social costs of $12, $40, $60, and $120 per short ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 in 2011 dollars.[141] When the Trump Administration conducted its RIA for the review of the CPP in 2017, it estimated the SC-CO_2 to be $6 per metric ton in 2020 (also in 2011 dollars) at the 3% discount rate, and $1 at the 7% rate.[142]

> Thus, in the span of just two years, the same government agency, utilizing the 'best available science' put forth estimates for the same metric that had changed by so many orders of magnitude

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[135] National Academies of Sciences, Engineering, and Medicine 2016. *Valuing Climate Damages. Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on Near-Term Update*:. Washington, DC: The National Academies Press ("NASEM 2016").

[136] Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social cost of Methane and the Social Cost of Nitrous Oxide ("2016b TSD"). OMB did not request or receive the NASEM's feedback on the new estimates of the social costs of methane and nitrous oxide, nor were they subject to notice and comment, or peer reviewed. Rather, they were premised entirely on a U.S. Environmental Protection Agency ("EPA") employee's 2015 paper, which at that point had not been reviewed or published. (*See* Martin, A.L., Kopits, E.A., Griffiths, C.W., Newbold, S.C., and A Wolverton. 2015. Incremental CH_4 and N_2O Mitigation Benefits Consistent with the U.S. Government's SC-CO_2 Estimates. *Climate Policy* 15(2): 272-298).

[137] 2016 TSD at 3.

[138] *See* Executive Order 13783 (March 28, 2017) ("E.O. 13783").[138]

[139] *Missouri v. Biden*, 4:41-cv-00287 (E.D. MO 2021) (Page 11 of Defendants' June 4, 2021 Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction) (emphasis added).

[140] These changes flowed from E.O. 13783 ("when monetizing the value of changes in greenhouse gas emissions resulting from regulations, including with respect to the consideration of domestic versus international impacts and the consideration of appropriate agencies shall ensure, to the extent permitted by law, that any such estimates are consistent with the guidance contained in OMB Circular A-4.")

[141] U.S. EPA, EPA-452/R-15-03 Regulatory Impact Analysis for the Clean Power Plan (2015) at 4-2. (The four SC-CO2 estimates differ based on use of discount rates of 5%, 3%, 2.5%, and the ninety-fifth percentile distribution at the 3% discount rate. (See 4-6, 4-7).

[142] U.S. EPA, Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal (2017) at 44. The conversion factor for metric ton to short ton is approximately 0.91, such that these estimates were actually about 9% lower when compared to the Obama-era estimates (2017 CPP RIA at 44).

> as to be farcical. This was the case even though the Trump and Obama analyses utilized the same underlying models.[143]

Just a few years later, the IWG has republished the prior 2016 SC-GHG values as the new Interim SC-GHG estimates, and as instructed by E.O. 13990, these estimates "tak[e] global damages into account" and utilize discount rates that the IWG believes "reflect the interests of future generations in avoiding threats posed by climate change."[144] As a result, the Trump Administration's estimated SC-CO_2 values of $1 and $6 per metric ton in 2020 (in 2011 dollars)[145] increased to $14, $51, $76, and $152 per metric ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 (in 2020 dollars).[146]

This whipsawing of SC-GHG estimates is not based on any objective errors or omissions. Indeed, the IWG and Trump Administration can both point to academic scholarship and regulatory guidance in support of their selections of discount rates and geographic scales. Rather, these divergent estimates demonstrate the extent to which any given estimate of the SC-GHG differs based on one or two subjective judgements. The output of the models is dependent on subjective framing decisions that "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[147] And because many of the key analytical framing decisions that truly drove model output are subjective and not purely scientific determinations, robust and transparent stakeholder and public engagement is essential.

As API urged in its comments on the 2021 TSD and reiterates here, the sensitivity of SC-GHG modeling output to one or a few subjective inputs raises serious questions of the SC-GHG estimates' reliability and utility in rulemaking and policy analyses. It also illustrates the profound importance of adopting analytical framing decisions through a structured and predictable process that is open, transparent, and data-driven. While EPA may have valid reasons for unilaterally developing its own SC-GHG estimates, API is concerned that this unexplained deviation from the SC-GHG estimation and updating process that was historically consigned and recently re-entrusted to the IWG reflects another *ad hoc* estimation approach that lacks the necessary structure, consistency, and transparency.

Moreover, given that EPA's SC-GHG Report contains the most recent estimate of the SC-GHG provided by the federal government, API is concerned that other federal agencies may opt to rely on the estimates in the EPA's SC-GHG Report rather than the estimates in the IWG's 2021 Interim TSD. While this concern is somewhat mitigated by E.O. 13990's requirement that agencies use the IWG's values, the absence of any clear statement from EPA as to what the SC-GHG Report is or how its estimates are to be used perpetuates a serious concern that EPA's values may be misapplied in a variety of different regulatory and administrative contexts.

III. DETAILED COMMENTS

API is concerned about the procedures EPA employed when developing the SC-GHG Report and the revised estimates contained therein. We also have substantive technical questions and concerns about the methodology EPA employed in generating the revised SC-GHG estimates and the manner in which the Agency presented its

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[143] Taylor, A. (2018). Why the social cost of carbon is red herring. Tulane Environmental Law Journal, 31(2), 345-372 at 347.

[144] E.O. 13990 at Sec. 5(a) and 5(b)(iii).

[145] Using discount rates of 7% and 3%.

[146] Interim TSD at Table ES-1 (using discount rates of 5%, 3%, 2.5%, and the 95th percentile of the 3% discount rate)

[147] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 370. [T]hose who would consider inclusion of IAM-generated estimates, particularly high-dollar ones, of the SCC to be an unmitigated success should nonetheless pay heed to the crow on the shoulder: a high degree of arbitrariness is currently baked into these estimates and it is quite difficult to know the degree to which they may be relied upon for accuracy or manipulated by agencies across different administrations.

estimates in the SC-GHG Report. Finally, API believes that EPA should more fully and explicitly explain why the inherent limits of the SC-GHG estimates render them unsuitable for agency rulemaking and decisions that require the SC-GHG to be expressed as a single value or within a reasonably narrow range of uncertainty. The subsections that follow discuss each of these three broad areas of concern in detail.

a. Procedural Concerns

As President Biden noted in Executive Order 13990 ("E.O. 13990") on his first day in office, "[a]n accurate social cost is essential for agencies to accurately determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses . . ."[148] To that end, E.O. 13990 further instructed that, in undertaking actions such as developing SC-GHG estimates, "the Federal Government must be guided by the best science and be protected by processes that ensure the integrity of Federal decision-making.[149] Consistent with that mandate, President Biden also issued a Presidential Memorandum to all heads of executive departments and agencies reaffirming the Biden Administration's commitment to the principles outlined in President Clinton's Executive Order 12866 ("E.O. 12866")[150], which established the basic foundation for executive branch review of regulations, and President Obama's Executive Order 13563 ("E.O. 13563"),[151] which "took important steps toward modernizing the regulatory review process."[152]

Thus, through the Regulatory Review Memorandum, President Biden reaffirmed his administration's commitment to "allow for public participation and an open exchange of ideas;"[153] using "best available techniques to quantify anticipated present and future benefits and costs as accurately as possible;"[154] and ensuring "the objectivity of any scientific and technological information and processes used to support . . . regulatory actions."[155]

One week later, President Biden reiterated to his executive departments and agency heads that "[i]t is the policy of my Administration to make evidence-based decisions guided by the best available science and data."[156] According to the President Biden's Scientific Integrity Memorandum, "[w]hen scientific or technological information is considered in policy decisions, it should be subjected to well-established scientific processes, including peer review where feasible and appropriate. . ."[157]

API supports the principles President Biden outlined in these Executive Orders and presidential memoranda, and believes that certain aspects of EPA's development of SC-GHG estimates, such as taking public comment and committing to peer review, are broadly consistent with these principles. In other respects, however, EPA's development of the SC-GHG Report thus far appears to be the product of an insufficiently structured and transparent process.

Indeed, EPA's SC-GHG Report represents an unexplained departure from the more structured, transparent, and collaborative interagency process that the Biden Administration promised when it encouraged stakeholders

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[148] E.O. 13990 at Sec. 5.

[149] E.O. 13990 at Sec. 1.

[150] Signed Sept. 30, 1993.

[151] Signed Jan. 18, 2011.

[152] Memorandum for the Heads of Executive Departments and Agencies regarding "Modernizing Regulatory Review" (Jan. 20, 2021) ("Regulatory Review Memorandum").

[153] E.O. 13563 at Sec. 1(a).

[154] E.O. 13563 at Sec. 1(c).

[155] E.O. 13563 at Sec. 5.

[156] "Memorandum on Restoring Trust in Government Through Scientific Integrity and Evidence-Based Policymaking" Memorandum From President Biden to the Heads of Executive Departments and Agencies (Jan. 27, 2021) ("Scientific Integrity Memorandum"). *See also* Executive Order 14007, which establishes the President's Council of Advisors on Science and Technology. (Jan. 27, 2021) ("E.O. 14007).

[157] Scientific Integrity Memorandum preamble.

interested in the SC-GHG development process to engage with the IWG. EPA's SC-GHG Report reflects no consideration of the comments API and others submitted to the IWG, and the limited data and time that EPA has provided at this stage does not appear consistent with a strong Agency interest in soliciting critical analysis. Furthermore, EPA's curious solicitation of comments on the SC-GHG Report within an NSPS rulemaking, which does not utilize the SC-GHG Report, does not particularly reflect an interest in transparency and collaboration. In fact, EPA's equivocal and fluctuating descriptions of the SC-GHG Report make it impossible for the public to even understand why EPA drafted the SC-GHG Report in the first place, or how the Agency intends to use it.

1. Lack of Clarity Regarding What the SC-GHG Report is and how it will be used

In both the preamble to the Proposed NSPS Revisions and the RIA in EPA's docket for the Proposed RIA Revisions ("Docketed RIA"), EPA concludes that the IWG's "interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science."[158] Therefore, the Agency "estimated the climate benefits of methane emission reductions expected from this proposed rule using the social cost of methane (SC-CH_4) estimates presented in the [IWG's 2021 TSD]."[159]

Having disclaimed that the RIA estimated the climate benefits of the proposal's anticipated methane reductions using only the interim SC-GHG estimates from the IWG's 2021 TSD, EPA's preamble to the Proposed NSPS Revisions then describes the SC-GHG Report as "a sensitivity analysis of the monetized climate benefits using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine."[160] According to EPA's preamble, the RIA presents the results of the SC-GHG Report's screening analysis in "Appendix B of the RIA."[161] However, the Docketed RIA does not include the sensitivity analysis EPA described in the preamble, nor does it contain any reference to, or even mention of, the SC-GHG Report.

Earlier versions of the RIA that were exchanged between and edited by EPA, OMB, and other agencies reflect that the RIA previously contained a substantial discussion of the SC-GHG Report and also included EPA's new estimates from the SC-GHG Report in a sensitivity analysis in a then-designated Appendix B.[162] These aspects of the draft RIA were deleted in their entirety without explanation shortly before publication of the Proposed NSPS Revisions. However, and particularly problematic from the perspective of transparency in public engagement as well as EPA's docket and rulemaking requirements under CAA Section 307, the version of the RIA that EPA posted on its website for public comment on November 11, 2022 contains the subsequently deleted discussion of the SC-GHG Report and Appendix B sensitivity analysis.[163] Thus, EPA is presently soliciting comments on two strikingly different versions of the Draft RIA. Indeed, while it is beyond the scope of this appendix's specific focus on EPA's SC-GHG Report, the Agency's publication of two divergent Draft RIAs raises significant questions about the sufficiency of the notice-and-comment opportunity on the required E.O. 12866 analysis as well as the Proposed NSPS Revisions.

While EPA's last minute revisions to the RIA remain unexplained, what is clear from the Docketed RIA is that EPA's SC-GHG Report is not a sensitivity analysis, and that the report's revised SC-GHG estimates are not amenable for use in sensitivity analyses. EPA's "Sensitivity and Uncertainty Analyses: Training Module" describes a "sensitivity analysis" as "a method to determine which variables, parameters, or other inputs have the most influence on the

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[158] 87 Fed. Reg. at 74,843; Docketed RIA (EPA-HQ-OAR-2021-0317-0173) at 3-6.

[159] 87 Fed. Reg. at 74,713; *See also* 87 Fed. Reg. at 74,843; *See also* the RIA in EPA's docket for the Proposed NSPS Revisions at 3-6.

[160] 87 Fed. Reg. at 74,843.

[161] 87 Fed. Reg. at 74,714, Table 5, note b; *See also* 87 Fed. Reg. at 74,843.

[162] *See* Draft RIA revisions between September and November 2021 at EPA-HQ-OAR-2021-0317-1540,1541, 1542, 1543, 1544, 1545, 1546, 1548, 1573, 1574, 1575, and 1576.

[163] *See* https://www.epa.gov/environmental-economics/scghg.

model output."[164] Consistent with this description, EPA's Training Module explains that "[t]here can be two purposes for conducting a sensitivity analysis [1] comput[ing] the effect of changes in model inputs on the outputs; [2] to study how uncertainty in a model output can be systematically apportioned to different sources of uncertainty in the model input."[165]

EPA's SC-GHG Report and the SC-GHG estimates contained therein are in no way suited to these purposes. The estimates in EPA's SC-GHG Report were derived in a manner wholly different from the IWG's SC-GHG estimates. For each of the four modules of the SC-GHG estimation process - socioeconomics and emissions, climate, damages, and discounting – EPA's SC-GHG Report uses different models, methodologies, analytical framing decisions, and data than the IWG utilized. As detailed in the Executive Summary to the SC-GHG Report:

> The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future Social Cost of Carbon Initiative . . . The climate module relies on the Finite Amplitude Impulse Response (FaIR) model… The socioeconomic projections and outputs of the climate module are used as inputs to the damage module to estimate monetized future damages from temperature changes. Based on a review of available studies and approaches to damage function estimation, the report uses three separate damage functions to form the damage module. They are: 1. a subnational-scale, sectoral damage function… 2. a country-scale, sectoral damage function… and 3. a meta-analysis-based damage function… The discounting module . . . us[es] a set of dynamic discount rates that have been calibrated following the Newell et al. (2022) approach, as applied in Rennert et al. (2022a, 2022b). … Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates. … Finally, the value of aversion to risk associated with damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. The estimation process generates nine separate distributions of estimates – the product of using three damage modules and three near-term target discount rates – of the social cost of each gas in each emissions year. To produce a range of estimates that reflects the uncertainty in the estimation exercise while providing a manageable number of estimates for policy analysis, in this report the multiple lines of evidence on damage modules are combined by averaging the results across the three damage module specifications.[166]

Every aspect of the above-described estimation process differs from the process employed by the IWG. And, because every aspect of EPA's SC-GHG estimation process differed from the IWG's process, it does not allow EPA "to determine which variables, parameters, or other inputs" in the IWG's estimation process "have the most influence on the model output." Examining two wholly different estimation processes does not provide any basis to discern how any of the IWG's inputs may impact the IWG's model output or apportion uncertainty to the IWG's various inputs.

"Sensitivity analyses" require the isolation and examination of one or a few model inputs while all other model parameters remain constant. For instance, in the 2021 TSD, the IWG advised that "agencies may consider

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[164] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).

[165] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).

[166] SC-GHG Report at 1-2.

conducting additional sensitivity analysis using discount rates below 2.5 percent."[167] Consistent with EPA's Training Module and standard practices for conducting sensitivity analyses, the IWG instructed that agencies' sensitivity analyses should isolate a single input (the discount rate) in order to assess the impact of changes from that single input on the model output.

The estimates in EPA's SC-GHG Report are simply new estimates based on new methods and data, and they therefore plainly have no value in any scientifically relevant sensitivity analysis. Indeed, what EPA deemed a "Screening Analysis" in the since-deleted sections of the Docketed RIA was not a screening analysis at all, at least as defined by EPA's Training Module. EPA merely compared the values from the IWG's 2021 TSD to EPA's SC-GHG Report and found that the benefits estimated in EPA's SC-GHG Report were higher than the IWG's 2021 interim estimates. This is truly the full extent of EPA's use of the SC-GHG Report for a "sensitivity analysis," which perhaps explains the Agency's decision to strike those references from the Docketed RIA.

Recognizing that neither EPA's SC-GHG Report nor the estimates contained therein constitute, or can credibly be used in sensitivity analyses, one is compelled to recognize the SC-GHG Report's estimates for what they are – SC-GHG values that are wholly separate and distinct from the 2021 IWG interim SC-GHG estimates that the Biden Administration directed all agencies to use. In fact, the SC-GHG Report itself never suggests its estimates are intended or even suitable for sensitivity analyses. The SC-GHG Report accurately describes them as "new estimates of the SC-GHG."[168]

Indeed, the SC-GHG Report's estimates are "new estimates of the SC-GHG," but given EPA's deletion of the supposed "sensitivity analysis" and assertion that the SC-GHG Report's estimates were not used in the RIA or the "statutory [best system of emissions reduction] determinations" in the Proposed NSPS Revisions,[169] commenters are left with no explanation why EPA developed the SC-GHG Report, how EPA intends to use the report's estimates, or why EPA included the SC-GHG Report in the docket for the Proposed NSPS Revisions. A truly transparent and collaborative process demands much more than this. EPA should provide a full and complete explanation for the development and intended use of the SC-GHG Report before subjecting it to peer review or public comment. Absent any explanation of the SC-GHG Report's intended use, reviewers have little basis to opine on its suitability.

2. Inconsistency with the Biden Administration's Stated Approach to the SC-GHG

From the earliest days of his Administration and consistently thereafter, President Biden and other Administration officials publicly committed to developing and updating government-wide SC-GHG estimates through the IWG by prescribing a detailed and incremental process. Based on the Administration's representations, API and other stakeholders devoted significant time and resources attempting to engage the IWG, but the rigorous and transparent IWG process that the Biden Administration promised has not yet materialized in any meaningful way. Now, more than two years after the IWG released its first and only publication of the several it had been charged with developing, EPA appears to be charting its own course by developing its own agency-specific SC-GHG estimates in the SC-GHG Report.

As discussed in more detail below, EPA's independent development of SC-GHG estimates is incompatible with and, in fact, undermines the unified approach promised by the Biden Administration in E.O 13990. We also describe

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[167] 2021 TSD at 4; *See also* 2021 TSD at 21 ("the IWG finds it appropriate as an interim recommendation that agencies may consider conducting additional sensitivity analysis using discount rates below 2.5%.").

[168] SC-GHG Report at 84.

[169] 87 Fed. Reg. at 74,843.

why EPA's unilateral SC-GHG estimates and any subsequent proliferation of agency-specific SC-GHG estimates contravene the Administration's stated interest in assessing the benefits and costs of proposed regulations consistently and cohesively across all federal agencies.

i. President Biden's Promised Approach for the Development and Agency use of SC-GHG Estimates

After the Trump Administration disbanded the IWG, President Biden on his first day in office issued E.O. 13990, which reestablished the IWG as the federal entity charged with developing and publishing the SC-GHG estimates that are to be used by all federal agencies.[170] The IWG's mission is fivefold:

> (A) publish an interim [SC-GHG] within 30 days of the date of this order, which agencies shall use when monetizing the value of changes in greenhouse gas emissions resulting from regulations and other relevant agency actions until final values are published;
>
> (B) publish a final [SC-GHG] by no later than January 2022;
>
> (C) provide recommendations to the President, by no later than September 1, 2021, regarding areas of decision-making, budgeting, and procurement by the Federal Government where the [SC-GHG] should be applied;
>
> (D) provide recommendations, by no later than June 1, 2022, regarding process for reviewing, and, as appropriate, updating, the [SC-GHG] to ensure that these costs are based on the best available economics and science; and
>
> (E) provide recommendations, to be published with the final [SC-GHG] under subparagraph (A) if feasible, and in any event by no later than June 1, 2022, to revise methodologies for calculating the [SC-GHG], to the extent that current methodologies do not adequately take account of climate risk, environmental justice, and intergenerational equity.[171]

Insofar as API is aware, the IWG has only completed the first of the five tasks prescribed by E.O. 13990.[172] Regarding these interim estimates, the E.O. mandates that "agencies ***shall*** use" them in promulgating their own "regulations and other relevant agency actions until final values are published."[173] Thus, although it is unclear why EPA developed the SC-GHG Report and how the Agency intends its SC-GHG estimates to be used, it bears mentioning that agencies deviating from these interim estimates do so in contravention with E.O. 13990.

The requirements of E.O. 13990 are also memorialized in the 2021 Interim TSD, which describes President Biden's directive that the reconstituted IWG "ensure that SC-GHG estimates used by the U.S. Government (USG) reflect the best available science and the recommendations of the National Academies (2017)…"[174] Consistent with the Executive Order, the IWG plainly recognized that the SC-GHG estimates it developed were to be used throughout the "U.S. Government," unless expressly precluded by statute.[175]

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[170] E.O. 13990 at Sec. 5.

[171] E.O. 13990 at Sec. 5(b)(ii).

[172] 2021 TSD.

[173] E.O. 13990 at Sec. 5(b)(ii)(a) (emphasis added).

[174] 2021 TSD at 3.

[175] Social Cost of Greenhouse Gas Emissions: Frequently Asked Questions (FAQs), ("OIRA Guidance") at 2, June 3, 2021. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/Social-Cost-of-Greenhouse-Gas-Emissions.pdf.

The IWG's Interim TSD goes on to instruct that the Interim SC-GHG estimates "should be used by agencies until a comprehensive review and update is developed in line with the requirements in E.O. 13990."[176] The Interim TSD also "determined that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates (2.5 percent, 3 percent, and 5 percent) as were used in regulatory analyses between 2010 and 2016 and subject to public comment."[177]

OMB, the entity responsible for coordinating the IWG efforts,[178] has likewise confirmed that President Biden's reconstitution of the IWG demonstrates that the President intended the IWG alone develop the SC-GHG estimates necessary "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[179] This directive is further confirmed in the June 2021 guidance document OIRA issued to agencies to assist in applying Section 5 of E.O. 13990.[180] The OIRA Guidance clarified that "[p]ursuant to E.O. 13990, when agencies prepare an assessment of the potential costs and benefits of regulatory action for purposes of compliance with E.O. 12866, they *must* use the 2021 interim estimates in monetizing increases or decreases in greenhouse gas emissions that result from regulations and other agency actions until updated values are released by the IWG."[181] Accordingly, E.O. 13990, the 2021 Interim TSD, OMB's solicitation of comments on the Interim TSD, and OIRA's guidance not only directed federal agencies to use the IWG's SC-GHG estimates, they apprised stakeholders interested in the federal government's SC-GHG estimates that the IWG was the sole entity with which to engage regarding the development of these important values.

In litigation surrounding E.O. 13990 and the 2021 Interim TSD, the U.S. Department of Justice ("DOJ") also describes the Biden Administration's stated approach to developing and using SC-GHG estimates, and opined on the degree to which E.O. 13990 compelled agencies to use the IWG's values:

> … the Executive Order requires agencies to use the Interim Estimates in some circumstances. *See* E.O. 13990 §§ 5(b)(ii)(A) (using the word "shall"); OIRA Guidance, at 1. But that directive is inoperative whenever the agency faces any conflicting statutory obligation . . .In other words, agencies will only ever rely on the Interim Estimates when they have discretion to do so…[182]

As DOJ stated elsewhere even more succinctly, "if an agency undertakes [SC-GHG] monetization, it shall use the Interim Estimates rather than another set of figures."[183]

ii. EPA's SC-GHG Report Contravenes the Approach President Biden Promised Stakeholders

Although it is not yet clear how EPA intends to use the estimates in its SC-GHG Report, the Agency's development and publication of these values appears to conflict with President Biden's explicit directive that the IWG develop the federal government's SC-GHG estimates and that federal agencies use those estimates. The Administration assigned this centralized role to the IWG "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[184] Even though EPA is a key member of the IWG and EPA's staff certainly

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[176] 2021 TSD at 4.
[177] 2021 TSD at 4.
[178] *See* E.O. 13990 at Sec. 5; *See also* 86 Fed. Reg. at 24,669.
[179] 86 Fed. Reg. at 24,669.
[180] *See* OIRA Guidance.
[181] OIRA Guidance at 1.
[182] Defendants' Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction, Page 23, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).
[183] Brief for Appellees, Page 40, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).
[184] 86 Fed. Reg. at 24,669.

have a high level of expertise in climate science and economic analysis, E.O. 13990's reestablishment of the IWG seems to indicate that the Biden Administration believed that development of the highly important SC-GHG estimates called for a breadth of expertise and diversity of opinions unlikely to be found within a single agency.

While API has often disagreed with the IWG's lack of transparency and with various modeling decisions and methodologies that the IWG has employed in developing SC-GHG estimates, we believe that the multi-agency composition of the IWG provides at least an opportunity to develop future SC-GHG estimates using a greater diversity of viewpoints and expertise. Thus, when the Biden Administration once again consigned the federal government's SC-GHG estimation process to the IWG, API once again devoted significant time and resources developing comments reflecting our own viewpoints and considerable expertise. Unfortunately, the IWG's unexplained inaction on the tasks it was assigned in E.O. 13990 along with EPA's unilateral development of SC-GHG estimates in contravention with E.O. 13990 seem to indicate that API's efforts to engage the IWG may have been in vain and that the process laid out in E.O. 13990 has been inexplicably abandoned.

API and others with a deep interest in, and credible expertise relevant to, the development of SC-GHG estimates are effectively precluded from meaningfully engaging with the federal government on these estimates if the Administration changes without explanation the entities, planned actions, and procedures for developing SC-GHG estimates.

The other reason the Administration re-established the IWG and tasked it with developing the SC-GHG estimates was "to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions in regulatory impact analyses."[185] This accords with OMB Circular A-4, which emphasizes that "[i]n undertaking [benefit-cost analysis and cost-effectiveness analysis], it is important to keep in mind the larger objective of analytical consistency in estimating benefits and costs *across regulations and agencies*, subject to statutory limitations."[186]

While we recognize that the Administration has announced its intent to revise Circular A-4,[187] the mere prospect of these revisions provides no basis for contravening the guidelines and instructions currently provided by Circular A-4. Unless and until Circular A-4 is revised or replaced, it should continue to guide EPA and other agencies to develop clear, transparently supported, objective, and consistent RIAs. Indeed, far from justifying any departures from Circular A-4's guidelines, the Administration's announcement that Circular A-4 will be revised further illustrates that EPA's unilateral development of SC-GHG estimates is inconsistent with the overall RIA and SC-GHG development framework that the Biden Administration publicly announced.

Finally, the need for a single consistent process for developing the SC-GHG estimates used in RIAs is further reflected in a 2020 Government Accountability Office ("GAO") Report on the SC-GHG and specifically the manner in which the federal government should address the recommendations of the National Academies."[188] Recognizing that the National Academies' recommended procedural and technical improvements could not be feasibly implemented by a multitude of different agencies, the GAO urged OMB to "identify a federal entity or entities to be responsible for addressing the National Academies' recommendations…"[189] GAO considered the recommendation "implemented" when E.O. 13990 reinstated the IWG.[190]

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[185] 2021 TSD at 10.

[186] OMB Circular A-4, Pages 9-10 (emphasis added).

[187] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.

[188] GAO-20-254, Report to Congressional Requesters, SOCIAL COST OF CARBON: Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis ("GAO-20-254").

[189] GAO-20-254.

[190] GAO-20-254 Recommendation Status, https://www.gao.gov/products/gao-20-254#summary_recommend.

Thus, EPA's unexplained deviation from the SC-GHG development approach laid out in E.O. 13990 not only upends the process to which API and other have devoted time and resources, it undermines the federal government's longstanding objective of making RIAs more consistent across agencies and detracts from what the GAO and this Administration identified as necessary to improve the SC-GHG estimation process consistent with the National Academies' recommendations.

3. Failure to Respond to Comments

As a further consequence of the Agency's decision to unilaterally develop its own SC-GHG estimates, EPA's SC-GHG Report does not appear to be based on any meaningful consideration of the many significant and detailed comments submitted to the IWG, including most recently, the many comments in response to the 2021 Interim TSD. Based on the Biden Administration's representation that the IWG alone would develop the SC-GHG estimates that would be used by the many agencies of the federal government, "[t]he Office of Management and Budget (OMB), on behalf of the cochairs of the Interagency Working Group on the Social Cost of Greenhouse Gases, including the Council of Economic Advisors (CEA) and the Office of Science and Technology Policy (OSTP)," requested "public comment on the interim TSD as well as on how best to incorporate the latest peer-reviewed science and economics literature in order to develop an updated set of SC–GHG estimates."[191]

Notwithstanding that the IWG purported to solicit public comments "in order to facilitate early and robust interaction with the public on this key aspect of this Administration's climate policy,"[192] neither the IWG nor EPA, which is a key member of the IWG, ever responded to or meaningfully considered the public comments submitted by API and many others in 2021. This does not represent a valid and transparent effort to engage the public and solicit feedback to improve agency decision-making.

"For an agency's decisionmaking to be rational, it must respond to significant points raised during the public comment period."[193] EPA is not relieved of this obligation simply because the comments were solicited by OMB on behalf of the IWG. As a key member of the IWG, EPA "reviewed the comments submitted to the IWG,"[194] and therefore had an obligation to "engage the arguments raised before it."[195]

The issues on which the IWG solicited comment, including advances in science and economics, approaches for implementing the National Academies' recommendations, approaches for intergenerational equity, and the use of discount rates,[196] are directly relevant to the EPA's SC-GHG Report. So too are the significant comments and data submitted by API and others in response to the IWG's solicitation.

In particular, API submitted detailed and constructive questions and comments on issues regarding the selection of discount rates, the ability to reasonably forecast impacts on expansive time horizons, and the importance of providing domestic SC-GHG values alongside global values. The IWG never responded to these comments and questions, and given the existence of these same concerns in EPA's SC-GHG Report, EPA plainly ignored API's comments as well.

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[191] 87 Fed. Reg. 24,669 (May 7, 2021).
[192] 87 Fed. Reg. at 24,670.
[193] *Allied Local & Reg'l Mfrs. Caucus v. EPA,* 215 F.3d 61, 68 (D.C. Cir. 2000).
[194] SC-GHG Report at 8.
[195] *Del. Dep't of Nat. Res. & Envtl. Control v. EPA*, 785 F.3d 1, 11 (D.C. Cir. 2015); *see Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 214 (D.C. Cir. 2013).
[196] 87 Fed. Reg. at 24,670.

It is not enough for EPA to suggest that it "has reviewed the comments submitted to the IWG in developing [the SC-GHG Report]."[197] EPA must respond in a reasoned manner to the comments received, [] explain how the agency resolved any significant problems raised by the comments, and [] show how that resolution led the agency to [its conclusion]."[198] "Consideration of comments as a matter of grace is not enough.' It must be made with a mind open to persuasion."[199]

It is also insufficient that EPA is now accepting comment on the SC-GHG Report. To begin, EPA's acceptance of comments on entirely new SC-GHG estimates in a wholly distinct SC-GHG Report in no way mitigates the absence of any record that EPA meaningfully engaged with or responded to any of the comments already submitted to the IWG.

Further, while it remains unclear what the SC-GHG Report is or how EPA intends to use it, nowhere does EPA represent that the report is in draft form or that the Agency will revise the SC-GHG Report based on comments and data received. On the contrary, EPA states that the "report presents new estimates of the SC-GHG" that EPA may rely upon "while [the IWG] process continues."[200] Therefore, if EPA intends to use and rely on the values in the SC-GHG Report as they are currently estimated, the Agency's solicitation of comments at this point does not truly "allow for public participation and an open exchange of ideas."[201] Nor is such an approach consistent with the National Academies' recommendation that draft revisions to the SC-GHG methods and estimates should be subject to public notice and comment, allowing input and review from a broader set of stakeholders, the scientific community, and the public.[202]

4. EPA has not Provided Interested Parties the Time or Information Necessary to Solicit Detailed and Constructive Feedback

In order for its public comment process to be reasonable and therefore lawful, EPA must provide commenters access to the data, studies, and other records on which the Agency relied as well as reasonably adequate time to review the data and draft comments analyzing EPA's conclusions and findings based on those records. EPA's present solicitation of comments on the SC-GHG Report does not satisfy either of these requirements.

The U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") makes clear that when an agency relies on data that is critical to its decision-making process, that data must be disclosed in order to provide the public an opportunity to meaningfully comment on the agency's rulemaking rationale.[203] Indeed, the D.C. Circuit has consistently maintained that "[i]n order to allow for useful criticism it is especially important for the agency to identify and make available *technical studies and data* that it has employed in reaching the decisions to propose particular rules."[204]

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[197] SC-GHG Report at 8.

[198] *Indep. U.S. Tanker Owners Comm v. Lewis*, 690 F.2d 908, 919 (D.C. Cir. 1982).

[199] *Advocates for Hwy & Auto Safety v. Fed. Hwy. Admin*., 28 F.3d 1288, 1292 (D.C. Cir. 1994) (citing *McLouth Steel Products Corp. v. Thomas*, 838 F2d 1317, 1323 (D.C. Cir. 1988)).

[200] SC-GHG Report at 84.

[201] E.O. 13563 at Sec. 1(a).

[202] National Academies of Sciences, Engineering, and Medicine 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*: Washington, DC: The National Academies Press ("NASEM 2017") at Pages 58-60.

[203] *See, e.g., Conn. Light & Power Co. v. Nuclear Regulatory Comm'n,* 673 F.2d 525, 530 (D.C. Cir. 1982); *Chamber of Commerce v. SEC,* 443 F.3d 890, 899 (D.C. Cir. 2006); *Am. Radio Relay League, Inc. v. FCC,* 524 F.3d 227, 236-37 (D.C. Cir. 2008).

[204] *Conn. Light & Power Co.,* 673 F.2d at 530 (emphasis added); *See also Am. Radio Relay League, Inc.,* 524 F.3d at 237 ("It would appear to be a fairly obvious proposition that studies upon which an agency relies in promulgating a rule must be made available during the rulemaking in order to afford interested persons meaningful notice and an opportunity for comment.").

Moreover, because of the "complex scientific issues involved in EPA rulemaking" Congress established more rigorous requirements under the CAA for making information available for public scrutiny.[205] Hence, the CAA mandates that "[a]ll data, information, and documents . . . on which the proposed rule relies *shall* be included in the docket on the date of publication of the proposed rule."[206] This critical requirement is particularly relevant here because EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, which is a rulemaking pursuant to the CAA.[207]

Therefore, if "documents of central importance upon which EPA intended to rely had been entered in the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."[208] "The Congressional drafters, after all, intended to provide 'thorough and careful procedural safeguards . . . [to] insure an effective opportunity for public participation in the rulemaking process.'"[209]

Notwithstanding this requirement, EPA's docket omits several studies, records, and other materials that appear fundamental to the Agency's development of the SC-GHG Report. For instance, EPA claims to have based several aspects of the SC-GHG Report on "the public comments received on individual EPA proposed rulemakings and the IWG's February 2021 TSD,"[210] but only identifies two supportive comments of the 88 total comments submitted on the 2021 TSD.[211] EPA did not identify or provide any comments "it received on individual EPA proposed rulemakings." Therefore, the Agency's administrative record for the SC-GHG Report is either insufficiently comprehensive or EPA impermissibly "rel[ied] on some comments while ignoring comments advocating a different position."[212]

Similarly, the SC-GHG Report relies extensively on SC-GHG estimation and modeling approach developed by RFF,[213] but while EPA's administrative record includes the RFF paper itself, it does not include all the data and studies that RFF utilized in developing those projections and estimates that EPA incorporated into its SC-GHG Report. For instance, RFF augments their economic forecast and generates their emissions forecast based on expert opinion,[214][215] but EPA's administrative record does not appear to contain any details or documentation regarding the expert elicitation and forecasting that was a key part of RFF's modeling effort. Given the critical importance of these forecasts in modelling the SC-GHG and EPA's implicit adoption of the forecasts in the SC-GHG Report, EPA should provide the public with details regarding how and why these experts were selected. For example, EPA should submit for public comment in the docket for the Proposed NSPS Revisions RFF's documentation, which details RFF's survey methodologies, partial selection methodology, and results. EPA should also extend the time period for submission of public comments on EPA's SC-GHG Report. Additionally, EPA should foster transparency by clarifying how RFF selected their experts from RFF's nominee pool.

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[205] *E.g., Small Ref. Lead Phase-Down Task Force v. EPA,* 705 F. 2d 506, 518 (D.C. Cir. 1983).

[206] CAA § 307(d)(3) (emphasis added); *see Kennecott Corp. v. EPA,* 684 F. 2d 1007, 1018 (CAA § 307(d)(3) requires EPA to place in the docket "the factual data on which the proposed regulations are based").

[207] 87 Fed. Reg. at 74,713.

[208] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (D.C. Cir.1981); *See also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C.Cir. 1982) (EPA improperly placed economic forecast data in the record only one week before issuing its final regulations).

[209] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (citing H.R.Rep.No.95-294, 95th Cong., 1st Sess. 188 at 319 (1977)).

[210] SC-GHG Report at 26, 37, 53, and 8.

[211] SC-GHG Report at 14 (FN26), and 15 (FN37).

[212] *National Women's Law Center v. Office of Management and Budget*, 358 F. Supp. 3d 66, 91 (D.D.C. 2019).

[213] Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. Brookings Papers on Economic Activity. Fall 2021, pp.223-305.

[214] Rennert et al.'s economic growth survey included the following participants: Daron Acemoglu, Erik Brynjolfsson, Jean Chateau, Melissa Dell, Robert Gordon, Mun Ho, Chad Jones, Pietro Peretto, Lant Pritchett, and Dominique van der Mensbrugghe.

[215] Rennert et al.'s future emissions survey included the following participants: Sally Benson, Geoff Blanford, Leon Clarke, Elmar Kriegler, Jennifer Faye Morris, Sergey Paltsev, Keywan Riahi, Susan Tierney, and Detlef van Vuuren.

More fundamentally, as discussed in Section III.a.1, EPA's administrative record does not even sufficiently apprise the public as to why EPA developed the SC-GHG Report or how the Agency intends to use it. However, even if EPA had timely provided all of the documents of central importance upon which it relied in drafting the SC-GHG Report, the public comment period EPA provided remains woefully insufficient. The SC-GHG Report provides a completely new set of SC-GHG estimates that were generated through a substantially revised modular approach using entirely different methodologies, models, studies, data, and analytical framing decisions than have been used by the IWG. And while EPA has not populated the administrative record with the full universe of the centrally important records on which it relied, there are hundreds of sources cited in the SC-GHG Report and the RFF Study that provided significant portions of the analysis used in the SC-GHG Report. As evidenced by the five years it took RFF to develop its SC-GHG estimates[216] and the fact that the IWG is more than a year overdue in developing the final SC-GHG estimates required by E.O. 13990, reviewing SC-GHG estimates and their underlying methodologies and data is incredibly labor-intensive and time-consuming.

As such, EPA's decision to provide the public only 69 days to review, develop, and submit comments on the SC-GHG Report is plainly unreasonable – particularly so, given that the comment period coincided with the holiday season. EPA's comment deadline for the SC-GHG Report is also unreasonable because it is the same comment period through which EPA is soliciting comments on the Proposed NSPS Revisions. The proposed revisions are complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under the CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, the current comment deadline is insufficient for even the Proposed NSPS Revisions alone.

In sum, EPA's current administrative record and comment deadline for the SC-GHG Report do not reasonably "allow for public participation and an open exchange of ideas."[217] API therefore respectfully requests that EPA supplement the administrative record with all of the centrally relevant information EPA utilized in developing the SC-GHG Report and provide a new and substantially longer comment period focused exclusively on the SC-GHG Report and the estimates contained therein.

b. Technical Issues with EPA's Methodology and Presentation of the SC-GHG Estimates

In addition to the procedural issues API described in the preceding subsection, our review of the SC-GHG Report raised several significant questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. It is critical the SC-GHG Report completely and transparently explain the precise bases for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Moreover, given the enormous and continually growing body of data and academic literature relevant to estimating the SC-GHG, the process by which EPA selects the data and literature on which it relies must be rigorous, objective, and transparent. Thus, when describing the evidentiary bases for its SC-GHG estimates, the SC-GHG Report should not only identify the studies on which the Agency relied, it must reasonably explain and describe why EPA declined to utilize other credible academic literature and data.

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[216] https://www.resources.org/archives/the-social-cost-of-carbon-reaching-a-new-estimate/?_gl=1*becwm3*_ga*OTczMDg2OTQzLjE2NzQ3NTAyOTI.*_ga_HNHQWYFDLZ*MTY3NDg0OTI4Ny4yLjEuMTY3NDg0OTMyMi4wLjAuMA.

[217] E.O. 13563 at Sec. 1(a).

The bullets below briefly describe a number of the questions and concerns that API and its members raised after reviewing the SC-GHG Report. Given the constrained timeframe for review and comment, these questions and concerns should by no means be considered exhaustive or complete. Rather, we urge EPA to view these questions and concerns as emblematic of API's broader concern with the manner in which the SC-GHG Report describes and supports EPA's model choices and SC-GHG estimation process.

- **Damage functions** – Two of the damage functions used in EPA's new SC-GHG model estimate damages at a subnational and/or sectoral level. However, there is no discussion about why EPA excluded other damage functions, particularly those produced by structural economy-wide models.[218] EPA should identify all the possible damage function approaches that could be incorporated and discuss the relative merits and shortcomings of each so stakeholders can understand EPA's rationale for their selected approach.

  Furthermore, given the relative importance of mortality-related impacts in the two sectoral damage functions, EPA should place more attention on how response functions could be adjusted for differences in age distributions across regions. Carleton *et al.* 2020 demonstrated that the temperature-mortality response function differs substantially by age, with a particularly strong relationship observed in the 65+ population. While age is included as a covariate in some of the studies included in Cromar *et al.* 2022, it is not uniformly considered across the literature assessed there. For example, the studies that do adjust for age do not present full mortality results by age. Cromar *et al.* did not consider heterogeneity by age group in their models estimating future mortality associated with temperature changes even though some of the individual studies included in Cromar *et al.* accounted for age. The ideal temperature-mortality model and subsequent monetization would account for age group heterogeneity at all stages of the analysis and calculations.

  Additionally, the temperature-mortality function for a given location and population will likely change through implementation of adaptation measures, a critical consideration in the SC-GHG estimation for mortality. However, adaptation is not consistently incorporated into these studies; and those studies that include adaptation vary in the way it is incorporated. In Carleton *et al.* 2020, administrative level 2 gross domestic product ("GDP") per capita and mean annual temperature for each location incorporates adaptation such that the location-specific exposure-response curve accounts for heterogeneity in adaptation response. Cromar *et al.* did not incorporate adaptation measures at a global or region-specific level, despite stating the importance of incorporating adaptation. As these measures will vary by many factors, including the regional climate and socioeconomic status, it is important that any future projections of the temperature-mortality function account for potential adaptation to temperature change, and the ideal study would account for adaptation at the local level.

- **Discount rate** – There are several choices regarding the discount rate that deserve more consideration and discussion. First, EPA should more fully justify its claim that long-term structural breaks in the interest rate imply lower interest rates in the future.[219] EPA should also explain how near-term interest rates from the last thirty years can fully inform the choice of an appropriate discount rate for the SC-GHG given the projection horizon of 300 years. Other work[220] has considered interest rates over long-time horizons and disputed the notion of structural breaks which calls into question some of EPA's discount rate assumptions. Furthermore, EPA should

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[218] Rose, S, D Diaz, T Carleton, L Drouet, C Guivarch, A Méjean, F Piontek, 2022. Estimating Global Economic Impacts from Climate Change. In Climate Change 2022: Climate Impacts, Adaptation, and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the IPCC, Chapter 16.

[219] *See* SC-GHG Report at 59.

[220] Rogoff et al. 2022. Long-Run Trends in Long-Maturity Real Rates 1311-2021. National Bureau of Economic Research.

explain their rationale for using a single discount rate for all regions, given that certain parameters used to estimate it, such as the economic growth rate, clearly vary across regions.

Second, since EPA estimates Ramsey parameters using assumptions about these near-term interest rates, EPA should consider whether the implied Ramsey parameters are reasonable and consistent with other available information. For example, the pure rate of time preference (ρ) that EPA estimates under the 2 percent near-term discount rate (0.2 percent) is significantly lower than those found in the Drupp *et al.*[221] survey cited in the SC-GHG Report.[222] Moreover, the value of ρ under the 1.5 percent near-term discount rate is near-zero, even though as EPA notes "it has been argued that very small values of ρ can lead to an unreasonable rate of optimal savings (Arrow et al. 1995), particularly with η around 1 (Dasgupta 2008, Weitzman 2007)."[223] Such results further call into question the choice of near-term discount rates and the reasons why parameters such as the Ramey parameters were forced to accommodate particular near-term discount rates, rather than the opposite.

Third, related to the calibration, EPA should state and explain how it calculates the near-term real growth rate of consumption per capita (g_t) as this is one of the few elements within the Ramsey discount rate that is observable in the market. To recover EPA's Ramsey parameters, a near-term consumption per capita growth rate of around 1.45 percent would seemingly be needed. Given that EPA appears to use the GDP per capita growth rate as a proxy for the consumption per capita growth rate, it is unclear why EPA derives its consumption per capita rate as the EPA notes "in the past decade average global per capita growth rates have been closer to 2%,"[224] and over the longer term global per capita growth rates have been higher. Once again, such results call into question why the growth rate was forced to accommodate other assumptions, rather than the opposite, given that the growth rate is the most observable of all the terms in the Ramsey equation.

Fourth, EPA should clarify how it estimates the near-term consumption growth rate "net of baseline climate change damages," and provide a practical example of how it calculated the consumption growth rate "net of baseline climate change damages" beyond what is offered in Appendix 3 of the SC-GHG Report. Moreover, EPA should discuss how climate damages affect the growth rate. If damages are assumed to impact investment (which would affect future economic output, and thus the growth rate), this seems to contradict EPA's assumption that damage functions are specified in consumption-equivalent units.[225]

Fifth, given the assumption of a constant savings rate, EPA should explain the basis for the specific savings rate and the methodology used. Similarly, EPA should discuss how the SC-GHG estimates would change if the savings rate varied at the national or regional given historical trends.

- **Geographic scope and reporting** – EPA lists several reasons for selecting a global SC-GHG—including the potential impacts on U.S. citizens living abroad, U.S. overseas military bases and investments, and regional destabilization caused by climate change. However, non-US impacts estimated by the damage functions used by EPA do not correspond to these impact categories. For example, total non-US mortality damages are not a reasonable estimate of the impacts on U.S. citizens living abroad. Therefore, EPA should consider and discuss reasonable alternatives for estimating potential impacts to U.S. interests that occur in other countries. In

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[221] Drupp *et al.* 2018. Discounting Disentangled. American Economic Journal: Economic Policy, 10 (4): 109-34.

[222] For the 1.5 percent consumption discount rate, EPA sets ρ to 0.01 percent and η to 1.02. For the 2 percent consumption discount rate, EPA sets ρ to 0.20 percent and η to 1.24. For the 2.5 percent consumption discount rate, EPA sets ρ to 0.46 percent and η to 1.42. Drupp *et al.*'s survey found that respondents' answers suggest a mean ρ value of 1.1 percent with a standard deviation of 1.47 and a median value of 0.5 percent.

[223] Drupp *et al.* 2018 at 61.

[224] SC-GHG Report at 22.

[225] *See* SC-GHG Report at 53.

addition, while EPA holds that not all spillover costs are properly attributed in regional breakdowns, as discussed further in Section III.c.1. below, the public would still benefit from SC-GHG estimates reported regionally, consistent with Circular A-4. EPA's SC-GHG Report also assumes that U.S. GHG mitigation activities, such as emissions pledges and the use of the global SC-GHG, engender international reciprocity. However, if EPA justifies the use of the global SC-GHG based on these factors, then the Agency should explain why its global emissions projection does not reflect globally coordinated action. Reasonable alternatives that maintain consistency between the geographic scope and the emissions trajectories should be considered and discussed.

- **Incorporation into regulatory cost-benefit analysis** – Given EPA's selection of a 1.5, a 2, and a 2.5 percent near-term discount rate, EPA's proposed SC-GHG discount rates no longer correspond to the typical regulatory consumption discount rate of 3 percent. Additionally, EPA's Ramsey discount rate approach further diverges from the constant discount rate approach used throughout federal cost-benefit analyses. Given that the announced revisions to Circular A-4[226] have not been finalized, API believes that it is inappropriate to incorporate EPA's new SC-GHG estimate in regulatory analysis until Circular A-4 is updated, as it is difficult to understand how EPA's SC-GHG approach for estimating climate benefits could be reasonably combined with other estimated benefits and cost streams discounted at different rates following standard A-4 guidance. For example, were EPA or another agency to use the EPA's SC-GHG estimates to present new benefit estimates in an RIA without updating the cost side of the ledger using the same near-term consumption discount rate used in the SC-GHG Report, the inconsistency between the discount rates used for benefits and costs would bias the cost-benefit analysis and undercut the rationality of the RIA's conclusions.

  EPA discusses the shadow price of capital, the preferred approach by Circular A-4, in Appendix 2 of the SC-GHG Report; however, EPA does not discuss whether or how the Agency plans to use this method in future cost-benefit analyses. To apply this method consistently, both benefits and costs must be adjusted in a similar manner. Whether this overall approach, or the revised discount rates themselves will improve cost-benefit analyses depends on whether and how Circular A-4 is updated to ensure consistency in how costs and benefits are estimated and compared. To avoid exacerbating inconsistencies, EPA should acknowledge this dependency and avoid using revised estimates until OMB guidance is updated, and all reviews are completed.

- **Underestimation of the SC-GHG** - EPA states that "The modeling implemented in this report reflects conservative methodological choices, and, given both these choices and the numerous categories of damages that are not currently quantified and other model limitations, the resulting SC-GHG estimates likely underestimate the marginal damages from GHG pollution."[227] This claim is repeated throughout EPA's SC-GHG Report. However, EPA should provide additional support for this assertion by listing and explaining the range of possible options and how the specific approach ultimately adopted by the Agency represents a conservative methodological choice. Repeating these assertions throughout the SC-GHG Report prior to completion of the IWG's peer review process may hamper objective analysis and may bias the IWG's review.

- **Market rates vs. purchase power parity** – EPA's SC-GHG Report states that "the shift to PPP-based projections in the RFF-SPs . . . represents another advancement in the science underlying the SC-GHG framework presented in this report."[228] However, Bressler and Heal (2022) contend that using "purchasing-power parity is incompatible with a pure Kaldor-Hicks approach."[229] Specifically, Bressler and Heal provide an example in which

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[226] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.
[227] SC-GHG Report at 2.
[228] SC-GHG Report 25.
[229] Bressler R., and Geffrey Heal. 2022. Valuing Excess Deaths Caused by Climate Change. National Bureau of Economic Research

a regulation would generate net costs when analyzed in PPP-adjusted dollars but would generate net benefits when analyzed using market exchange rates. EPA should therefore explain how using PPP-adjusted dollars is compatible with the federal government's overall approach to cost-benefit analysis.

c. The SC-GHG Report Should Fully and Explicitly Discuss the Limited Utility of the SC-GHG Estimates

EPA's SC-GHG Report avers that the SC-GHG estimates allow "analysts to incorporate the net social benefits of reducing emissions of greenhouse gases (GHG), or the net social costs of increasing such emissions, in benefit-cost analysis and, when appropriate, in decision-making and other contexts."[230] API agrees that from its earliest development by the IWG, the SC-GHG "was explicitly designed for agency use pursuant to E.O. 12866."[231] That is why the titles of each of the six TSDs the IWG published prior to the 2021 TSD disclaimed that they were "for Regulatory Impact Analysis under Executive Order 12866."[232]

While API agrees with the SC-GHG Report's statement that SC-GHG estimates are used in benefit-cost analysis, we believe EPA should clarify and describe the "decision-making and other contexts" the Agency believes may appropriately be based on SC-GHG estimates.[233] API agrees with the need to take action on climate change and we agree that agencies generally should weigh costs and benefits when considering such actions, but given the significant uncertainty and recognized malleability of SC-GHG estimates through modest changes to one or a few inputs, we cannot support expanded use of the Agency's or the IWG's SC-GHG estimates beyond their originally intended application in cost-benefit analysis. Indeed, in addition to, and in fact because of, the ease with which they can be "manipulated to reflect preferences, philosophies, assumptions, and so on,"[234] the SC-GHG estimates reflect such a broad range of uncertainty that in some contexts they may not effectively assist agencies' broad weighing of costs and benefits, as envisioned in E.O. 12866.

The SC-CH_4 values in EPA's SC-GHG Report and the IWG's 2021 TSD illustrate how agencies can struggle to use the estimates to determine whether a particular course of action will deliver more benefits than costs or *vice versa*. In the SC-GHG Report, the "nine separate distributions of estimates"[235] for avoided SC-CH_4 damages in 2030 range from $1,100 per metric ton to $3,700 per metric ton.[236] The 2021 TSD's estimates for avoided SC-CH_4 damages in 2030 range even more widely from $940 per metric ton to $5,200 per metric ton.[237] From a policy and regulatory perspective, the difference between $940 and $5,200 per metric ton or even $1,100 and $3,700 per metric ton is immense. A regulatory action that is imminently justifiable to mitigate damages estimated at the higher end of these ranges may be preposterous if proposed to avoid damages estimated at the lower end of these ranges.

"Such a wide range of . . . SC-CO_2 estimates is little more than a mathematical affirmation of the federal court's judgment that 'the value of carbon emissions reductions is certainly not zero.'"[238] "However, for the purpose the .

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[230] SC-GHG Report at 1.
[231] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.
[232] *See* 2010 TSD; May 2013 TSD; May 2013 TSD (revised); November 2013 TSD; August 2016a TSD (for CO_2); and August 2016b TSD (for Methane and Nitrous Oxide).
[233] API urged the IWG to provide the same clarification on multiple occasions.
[234] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 366.
[235] SC-GHG Report at 66.
[236] SC-GHG Report at 68.
[237] 2021 TSD at 5.
[238] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

. SC-CO_2 was developed— . . .RIAs[] for US federal regulations—such a wide range of SC-CO_2 is not necessarily a problem."[239]

The Electric Power Research Institute ("EPRI") examined 65 federal rules and 81 subrules between 2008 and 2016 that utilized the IWG's SC-CO_2 estimates in their regulatory analyses.[240] EPRI found that "the inclusion of benefits from policy-induced CO_2 emissions changes does not change the sign of net benefits. In other words, the net benefits are positive with and without consideration of CO_2 reduction benefits."[241]

Thus, while the broad range of uncertainty inherent in the IWG's SC-GHG estimates would appear to preclude their use in most cost-benefit analyses, in practice, the estimates have been used in analyses in which the difference between costs and benefits was larger than the SC-GHG estimates' range of uncertainty. This demonstrates that for those actions with non-climate benefits that are already estimated to exceed costs by a substantial margin, the IWG's SC-GHG estimates' range of uncertainty will not matter.

The extent of uncertainty and speculation that besets the SC-GHG estimates developed by the IWG and EPA alike precludes their reduction to a single value, be it a central value or otherwise. The IWG's SC-GHG estimates "were developed . . . with a methodology to fit the specific purpose of a benefits estimate to be added to a regulatory impact analysis . . ."[242] While EPA's SC-GHG Report adopts a modular approach in lieu of reliance on the IAMs used by the IWG, the reality of the SC-GHG estimation process is "that a high degree of uncertainty is baked in and cannot reasonably be estimated away."[243] At best, this enterprise is capable of producing "a very wide range of potential" SC-GHG estimates.[244]

> In aggregate, the SCC estimates developed by the interagency working group and others represent a strange marriage of conventional economic-financial logic, arbitrary economic-financial logic, massively expansive biophysical phenomena, preference, and uncertainty management utilized to create a digestible input – a dollar amount – for use in the dominant cost-benefit analysis . . . framework.[245]

Moreover, the subjective judgements that are necessary inputs into the SC-GHG estimation process make the product of those modeling exercises malleable. Indeed, SC-GHG estimates "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[246] Thus, "[f]or these assumptions, the tools of science, economics, or statistics are incapable of providing a 'best' or single value."[247]

> [P]roducing a wide range of SC-CO_2 estimates is simply the best we can do using this methodology, and it is the best we will ever be able to do. The . . . Central SC-CO_2 is not an optimal price of CO_2 emissions or a best estimate of the benefits of CO_2 reductions. It is a noncomprehensive estimate

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[239] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[240] Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.

[241] Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.

[242] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[243] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 364-5.

[244] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[245] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 348.

[246] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 369.

[247] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

> of the benefits of GHG reductions using one set of assumptions that is arguably defensible given the theoretical and methodological challenges associated with the approach.[248]

In addition to the methodological limitations precluding the use of the SC-GHG estimates in royalties, subsidies, fees, or applications that require a single value or narrow range of uncertainty, there are legal, statutory, and practical constraints on more expansive use of SC-GHG estimates as well. Indeed, courts have generally only upheld agencies' use of the SC-GHG estimates in the context of cost-benefit analyses.[249]

While some courts have held that agencies must estimate the costs of GHG emissions when assessing impacts of their proposed actions under the National Environmental Policy Act ("NEPA"), the agencies' impact assessments in those cases typically included cost-benefit analyses that are not required by NEPA.[250] In other words, because the agencies there estimated quantified benefits of certain actions, they also had to estimate quantified costs including of GHG emissions. In many other cases, courts have held that agencies have no obligation to use the SC-GHG estimates in analyzing impacts under NEPA.[251] Indeed, many of these courts took favorable views of agency determinations that SC-GHG estimates are ill-suited for NEPA analyses based on uncertainty ranges or otherwise.[252] Courts have generally taken a similar view to the Federal Energy Regulatory Commission's ("FERC's") prior position that the SC-GHG estimates' broad variability range makes them unsuited for public interest determinations[253] under the Natural Gas Act.[254] And in the context of collecting royalties and other financial obligations related to the leasing, production, and sale of minerals from federal and Indian lands, the federal government is affirmatively prohIbited from considering the SC-GHG estimates.[255]

Indeed, regardless of whether the Administration continues to rely on the IWG's estimates or those newly proffered by EPA in the SC-GHG Report, the SC-GHG estimates' broad range of variability and uncertainty render them inappropriate for use in any project-level or site-specific application. In addition, while analyses at these scales might be capable of monetizing some impacts (such as projected climate impacts), partial monetization is not advisable for several reasons. First, it could be interpreted as emphasizing or de-emphasizing the monetized impact, even though there is no basis on which to conclude that a monetized impact is more or less significant than a non-monetized impact. Second, monetized benefits and costs are only meaningful when they are compared to one another in aggregate.

These considerations illustrate the material distinction between formalized cost-benefit analysis in the regulatory context and other types of analysis. Whereas monetization is essential for regulatory analyses, it is potentially misleading outside this application for reasons discussed above. Notably, this material distinction is also embodied

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[248] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[249] Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 416.

[250] *High Country Conservation Advocates v. U.S. Forest Serv.*, 52 F. Supp. 3d 1174,1181, 1184 (D. Colo. 2014); *See also Mont. Envtl. Info. Ctr. v. U.S. Office of Surface Mining*, 274 F. Supp. 3d 1074, 1096-98 (D. Mont. 2017); *See also Citizens for a Healthy Community v. BLM*, 377 F.Supp. 3d 1223 (D. Col. 2019); *Contrast with WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41; *See also* Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 415.

[251] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020); *See also Citizens for a Healthy Cmty v. U.S. Bureau of Land Mgmt.*, 377 F. Supp. 3d 1223, 1239-40 (D. Colo. 2019); *See also WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 76 (D.D.C. 2019); *See also Wilderness Workshop v. U.S. Bureau of Land Mgmt.*, 342 F. Supp. 3d 1145, 1159 (D. Colo. 2018); *High Country Conservation Advocates v. Forest Service*, 333 F. Supp. 3d 1107 (D. Colo. 2018); *See also W. Org. of Res. Councils v. U.S. Bureau of Mgmt*., No. CV 16-21-GFBMM, 2018 WL 1475470, at *13 (D. Mont. Mar. 26, 2018).

[252] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020).

[253] *See* Natural Gas Act,15 U.S.C. § 717f(a), (c) (2012).

[254] *See, EarthReports, Inc. v. Fed. Energy Reg. Comm'n*, 828 F.3d 949,. 953-54 (D.C. Cir. 2016); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 867 F.3d 1357, 1375 (D.C. Cir. 2017) (remanding to FERC for a discussion of whether it still holds the *EarthReports* position); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 672 Fed. Ap 'x 38 (D.C. Cir. 2016).

[255] *See Wyoming v. Jewell*, No. 2:16-CV-0285-SWS (Oct. 10, 2020); *See also* 86 Fed. Reg. 31,196, 31,206 (June 11, 2021).

in E.O. 12866, which distinguishes between "regulatory actions" and "significant regulatory actions" based in part of the projected scale of impact.[256] For each "significant" proposed action, the issuing agency is required to provide a cost-benefit analysis. Thus, existing regulatory guidance essentially equates significance with the need for cost-benefit analysis, which in turn, implies full monetization of costs and benefits. While (as discussed above), there are inherent limits to the usefulness of SC-GHG estimates in rulemaking, consideration of SC-GHG values is sensible in situations where all costs and benefits are monetized. Consideration of the SC-GHG estimates is not appropriate in instances where only a subset of impacts can be monetized; accordingly, restricting its use to significant regulatory actions ensures consistency with this principle.

d. The SC-GHG Report Needlessly Limits the Utility of EPA's SC-GHG Estimates by Failing to Present Domestic SC-GHG Estimates Alongside Global Estimates

In order to conduct a valid and legally-defensible cost-benefit analysis, agencies must ensure that they weigh costs and benefits of the same scale and of the same type. Therefore, consistent with API's repeated requests to the IWG, API recommends that EPA's SC-GHG Report present domestic SC-GHG estimates alongside global estimates. Indeed, we believe that, absent a clear congressional directive otherwise, agency cost-benefit analyses should be constructed to weigh domestic costs against domestic benefits. By doing so, agencies can better ensure that projected domestic impacts alone justify the costs to be imposed on domestic industries. When agencies have failed to do so and weighed domestic costs against global benefits, they have effectively put their thumb on the scale in favor of regulatory action. Such an analysis is not only inconsistent with basic economic principles it overlooks "the more prosaic commonsense notion that Congress generally legislates with domestic concerns in mind."[257]

Given that EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, the CAA provides a particularly relevant example of why the geographic scope of agencies' regulatory analyses should reflect the intended scope under which the regulation is proposed or promulgated.[258] In CAA Section 101(b)(1), Congress expressly stated that the statute's purpose is to "protect and enhance the quality of the *Nation's* air resources so as to promote the public health and welfare and the productive capacity of *its population*."[259] By focusing on "the Nation" and "its population," Congress clearly demonstrated that it enacted the CAA to affect domestic air quality.

This interpretation of the CAA is not new, nor does it fail to reflect the global nature of climate change. Indeed, EPA relied on this interpretation when it issued the highly important Endangerment Finding on which multiple federal climate change regulatory actions have been based.[260]

In addition to the clear inferences that can be drawn from Congress' statements of statutory intent, the text of specific provisions of the statute confirms that Congress intended to limit the reach of the Act to domestic effects, unless it expressly provided otherwise. In only two discrete instances, Congress explicitly addressed the foreign effects of domestic air emissions in the CAA.

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[256] *See* E.O. 12866 at Sec. 3.

[257] *RJR Nabisco, Inc. v. Eur. Cmty.*, 136 S. Ct. 2090, 2100 (2016).

[258] 87 Fed. Reg. at 74,713.

[259] CAA § 101(b)(1) (emphasis added).

[260] *See* Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the CAA, 74 Fed. Reg. 66496, 66514 (Dec. 15, 2009) ("[T]he primary focus of the vulnerability, risk, and impact assessment is the United States").

First, in Title I of the Act, Congress authorized EPA to consider the foreign effects of domestic air emissions within the delineated framework of Section 115. There, Congress defined the process for EPA to evaluate and address reports of domestic air pollution possibly affecting public health or welfare in a foreign country.[261] Critically, this only applies when the Administrator finds there is "reciprocity" such that "the United States essentially [has] the same rights with respect to the prevention or control of air pollution occurring in that country as" Section 115 gives to the foreign country.[262]

Second, in Title VI of the CAA, Congress addressed the global impacts of domestic stratospheric ozone emissions by, among other actions, listing ozone-depleting chemicals of concern, establishing reporting requirements for manufacturers and other entities, and phasing out the production of certain chemicals.[263] Congress expressly enacted Title VI in 1990 in order to implement the Montreal Protocol on Substances that Deplete the Ozone Layer, an international treaty signed by the United States, which addresses stratospheric ozone.[264]

These two discrete provisions (Section 115 and Title VI) represent the full extent of EPA's authority to consider the international benefits of domestic regulation. Critically, these provisions demonstrate that, when Congress chose to allow the Agency to consider foreign impacts of domestic regulation, it said so expressly. These two provisions also reflect the very narrow purpose for which Congress allowed EPA to consider foreign impacts of domestic regulation. Both provisions deal with international agreements under which the United States and one or more foreign nations make reciprocal commitments to impose regulations within their borders that confer benefits outside their borders and/or to the other party.

In these two narrow circumstances, the United States is the beneficiary of EPA's action and also the foreign nation's reciprocal regulatory action. As such, while foreign impacts are considered, their consideration is solely intended to inform regulatory decisions seeking to maximize domestic benefits of reciprocal regulatory actions. The executive branch has ample authority to act for the benefit of foreign nations, but the CAA is generally not one of the statutes that confers that authority. With the exception of these two discrete provisions, the CAA arguably precludes EPA from weighing international benefits against domestic costs.[265]

In addition to the limitations that the CAA places on EPA specifically, OMB guidance applies these same principles government-wide. In support of limiting the use of international benefits for justifying regulation, OMB directs agencies developing regulatory analyses to focus on the "benefits and costs that accrue to citizens and residents of

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[261] CAA § 115(a)-(b).

[262] CAA § 115(c).

[263] EPA, 1990 CAA Amendment Summary: Title VI (Jan. 4, 2017), https://www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary-title-vi.

[264] 42 U.S.C. § 7671m(b) ("This subchapter as added by the CAA Amendments of 1990 shall be construed, interpreted, and applied as a supplement to the terms and conditions of the Montreal Protocol.").

[265] Settled principles of statutory interpretation further confirm that Congress did not intend to authorize EPA to rely on the foreign effects of U.S. emissions in promulgating regulations under the CAA. For one, statutes are construed to give effect to all provisions. *See, e.g., Hibbs v. Winn*, 542 U.S. 88, 101 (2004) ("A statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or superfluous, void or insignificant….") (citations omitted). Section 115 would effectively be a nullity if EPA read the Act to provide the Agency with the authority to consider effects of domestic emissions on foreign countries without following the Section 115 process. Moreover, it is also a well-settled canon that if Congress addressed an issue in one provision, its failure to address that same issue elsewhere confirms its limited intent. *See, e.g., Russello v. United States*, 464 U.S. 16, 23 (1983) ("[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (citations omitted).

the United States"[266] and directs agencies which "choose to evaluate a regulation that is likely to have effects beyond the borders of the United States" to report those impacts "separately."[267] OMB's guidance further states that an agency's cost-benefit analysis "should focus on benefits and costs that accrue to *citizens and residents of the United States*."[268]

Notwithstanding that OMB Circular A-4 mandates agency consideration of domestic costs and benefits while simply allowing for optional consideration of non-U.S. benefits, EPA's SC-GHG Report omits any calculation of domestic benefits. In lieu of this important, and arguably mandatory presentation of domestic benefits, the SC-GHG Report merely offers the EPA's justification for its absence.[269] While these justifications are perhaps sufficient to support the EPA's decision to present global benefits in the SC-GHG Report, none explain the Agency's refusal to also present an estimate of domestic benefits alongside the global value.

For instance, the IWG argues that analyzing the global benefits of U.S. regulatory actions can help generate reciprocal actions from other countries and "allows the U.S. to continue to actively encourage other nations . . . to take significant steps to reduce emissions."[270] Even assuming such effect occurs, the goal of the SC-GHG estimation process should not be the development of tools to aid in international negotiations or which help the U.S. "actively encourage" reciprocal actions on climate change; President Biden required use of the "best available economics and science"[271] to estimate as accurately as possible the societal costs of adding a small increment of GHG into the atmosphere in a given year. To the extent EPA is attempting to assume the IWG's assigned role of developing SC-GHG estimates, the Agency must also assume the obligation to dispassionately and objectively estimate the SC-GHGs using "best available economics and science."[272] And that obligation cannot be construed to encompass an advocacy role. Even if it were reasonable for EPA's interest in advocating for intergovernmental cooperation to shape how it estimates the SC-GHG, the EPA's SC-GHG Report provides no explanation why that advocacy role would be undermined by the presentation of domestic benefits *alongside global benefits*.

EPA also offers that:

> The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to the U.S. population.[273]

Although the U.S. could be adversely impacted by potential climate change damages that could occur in other countries, it does not follow that the EPA must therefore include the potential *damages in those other countries* as part of the SC-GHG estimate. Rather, the Agency should include in the SC-GHG estimates the potential *domestic impact* of those reasonably projected extraterritorial climate damages. As explained by the NASEM:

> Correctly calculating the portion of the SC-CO_2 that directly affects the United States involves more than examining the direct impacts of climate that occur within the country's physical borders . . .

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[266] OMB, Circular A-4, at 15.
[267] OMB, Circular A-4, at 15.
[268] OMB, Circular A-4, at 15 (emphasis added).
[269] *See* SC-GHG Report at 10-15
[270] SC-GHG Report at 14.
[271] E.O. 13990 at Sec. 5(b)(ii)(D).
[272] E.O. 13990 at Sec. 5(b)(ii)(D). Notably, and as previously discussed, E.O. 13990 expressly assigned the SC-GHG estimation development process to the IWG and precluded agencies from developing and using their own values.
[273] SC-GHG Report at 11.

> Climate damages to the United States cannot be accurately characterized without accounting for consequences outside U.S. borders.[274]

In other words, regardless of whether climate change imposes costs on the U.S. directly or indirectly through potential damages in other countries, the costs EPA should be attempting to characterize are those anticipated to be borne by the U.S. and its citizens. Thus, the global nature of climate change is consistent with and supported by the presentation of domestic benefits in the SC-GHG estimates. And the global nature of this issue certainly does not explain why the domestic benefits should not at least be presented alongside projections of global benefits.

EPA's final rationale for declining to present domestic benefits alongside global values is that there are relatively few region- or country-specific SC-GHG estimates or models with sufficient resolution to estimate SC-GHG benefits on a country-specific basis.[275] At the same time, EPA has largely limited its own consideration of damage functions to those that can be specified at the national or sub-national level, suggesting that domestic impacts could be reasonably estimated in two of the three frameworks adopted.[276] Although we agree that there is a high level of uncertainty in the regional or country-specific SC-GHG estimates, we believe it is inconsistent for EPA to use this uncertainty to rationalize its decision to decline to provide any SC-GHG estimates other than global, particularly given EPA's decision to severely restrict consideration of damage functions to precisely those that provide such information. Uncertainty and speculation pervade every aspect of the SC-GHG estimates, and the Agency should explain why such uncertainty provides a valid basis to decline to render estimates in this instance, but presents no barrier in every other respect.

It is also increasingly inaccurate for EPA to cite the overall paucity of literature on regional and country-specific SC-GHG estimates. As noted by the NASEM in 2017:

> Estimation of the net damages per ton of CO_2 emissions to the United States alone, beyond the approximations done by the IWG, is feasible in principle; however, it is limited in practice by the existing SC-IAM methodologies . . .[277]

Indeed, EPA's SC-GHG Report identifies a number of new models and academic efforts that have enhanced our ability to model SC-GHG benefits with greater spatial resolution.[278] While these country-specific estimates remain highly uncertain and divergent, they all broadly agree that the SC-GHG in the U.S. is a small fraction of the SC-GHG Report's estimates of the global SC-GHG.

Although country-specific SC-GHG estimates remain quite imprecise, they are highly relevant because EPA and other agencies should not adopt rules which could impose massive costs on the U.S., but for which the claimed benefits primarily accrue overseas—certainly not without a clear and explicit directive from Congress. EPA's assertion that rule writers and policymakers use only the global SC-GHG estimates in cost-benefit analysis results in

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[274] NASEM 2017 at 52-53.

[275] SC-GHG Report at 77-80.

[276] SC-GHG Report at 39 ("Based on a review of available studies using these approaches, the SC-GHG estimates presented in this report rely on three damage functions. They are: 1. a subnational-scale, sectoral damage function estimation (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (CIL 2022, Carleton et al. 2022, Rode et al. 2021)), 2. a country-scale, sectoral damage function estimation (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert et al. 2022b)), and 3. a meta-analysis-based global damage function estimation (based on Howard and Sterner (2017)).").

[277] NASEM 2017 at 53.

[278] SC-GHG Report at 77-80.

a significant misalignment of costs and benefits, particularly for regulatory actions, like the Proposed NSPS Revisions, that are promulgated pursuant to the CAA.

As such, API's modest recommendation, which we have also previously voiced to the IWG, is not that the federal government abandon the global SC-GHG estimates, but that it simply present domestic SC-GHG estimates alongside global values. This approach would allow risk managers to more readily align the costs with the benefits. Consistent with OMB guidance, the costs of a rule for entities in the U.S. should be presented in comparison with the benefits occurring in the U.S.

IV. CONCLUSION

API appreciates the opportunity to provide these comments on EPA's SC-GHG Report. We hope this comment opportunity is the first step toward a more open and transparent process for developing SC-GHG estimates and the judgment and assumptions used to develop and portray those estimates.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, EPA's unilateral development of SC-GHG estimates raises a number of questions and concerns the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the IWG.

President Biden's issuance of E.O. 13990 on his first day in office reflects the importance of the SC-GHG estimates to our nation's climate policies and regulations. Given the importance of these estimates, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each module had been updated and the SC-GHG Report had been fully drafted. Moreover, given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is wholly insufficient for soliciting detailed feedback from informed stakeholders.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. In fact, EPA has not even clearly explained why it developed the SC-GHG Report or how it intends the SC-GHG Report's estimates to be used. Nonetheless, where possible, API has tried to provide EPA relevant analysis and constructive recommendations for improving the reliability and utility of the SC-GHG Report and the estimates therein. We did so, not only with the intent of improving the SC-GHG estimates and the process through which they are developed, but with the hope that by providing credible analysis and constructive feedback, EPA would more fully recognize the benefit of engaging stakeholders in a more open, data-driven, and collaborative process.

API recognizes the need to confront the challenges of climate change. However, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. Indeed, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.

Thank you again for your consideration of these comments. If you have any questions or would like to discuss these comments, please feel free to contact Andrew Baxter at (202) 268-2800 or baxtera@api.org.

Sincerely,

Andrew Baxter
Economic Advisor, Policy Analysis
American Petroleum Institute

ANNEX D: API Barnett and Bakken Mantis Field Studies

PROVIDENCE
PHOTONICS

American Petroleum Institute Mantis™ Field Study

Final Report | Revision 1.0

September 2023

PROJECT 0040-001

API BARNETT

PREPARED BY
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Table of Contents

Introduction

Providence Photonics, LLC (Providence) has developed a method to remotely measure the performance of an industrial flare using Video Imaging Spectral Radiometry (VISR). The VISR method provides five flare performance metrics: combustion efficiency (CE), smoke index (SI), flame stability (FS), flame footprint (FF), and fractional heat release (FH). The VISR method is incorporated into Providence's Mantis™ flare monitoring product (Mantis).

Providence used the Mantis device to conduct a flare measurement in the Barnett regions for American Petroleum Institute (API) in September of 2023. The measurements were performed from September 11th, 2023 to September 16th, 2023. This report summarizes the Mantis data and associated findings from the study.

Background

The VISR method utilizes a multi-spectral mid-wave infrared imager to measure the radiance from both hydrocarbons being combusted and carbon dioxide (CO_2) as complete combustion product, and use that information to determine the combustion efficiency. The method was designed to be a continuous and autonomous remote flare monitor, but in this study it was deployed as a mobile technology for a short-term measurement. ***Figure 1*** below shows the Mantis device deployed at one of the sites during the Barnett study.

Figure 1: Mantis deployed during API field survey in Barnett region.

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%. CE should not be confused with Destruction and Removal Efficiency (DRE). The difference between these two metrics is discussed in **Appendix C**. While CE is directly measured by the VISR method, DRE is derived using correlations established through extractive sampling as discussed in **Appendix C**.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 3 generally indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the Mantis flare monitor. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the Mantis flare monitor in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope, the outer layer of the flame where the combustion process has ceased. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this study, any measurements with less than 30 pixels were removed from the summary tables and **Appendix A**.

The second important DQI is the Smoke Index level. As the smoke index increases above 3.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Testing has shown that SI values above 3.0 may cause a small negative bias on the CE measurement by VISR (< 1%) and SI values above 5 may cause a significant negative bias to CE measured by VISR, as confirmed by testing with an extractive sampling method as a control (note that in the extractive sampling method, carbon soot is not included in the CE calculation). Any data points with a smoke index above 5 were removed from the summary tables and **Appendix A** as they are considered outside of method limits.

Observations

The following sections describe field observations and comparisons derived from the dataset.

Aggregate results

The flare measurements included sites from three companies ([redacted] In total, there were 39 individual flares measured. The distribution of the DRE measurements is represented in ***Figure 2*** below.

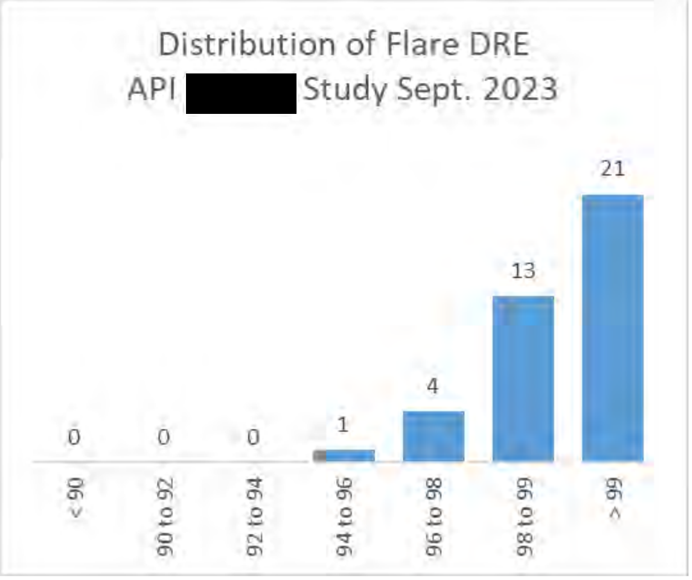

Figure 2: HP and LP flare tips on Green Canyon 254.

Summary

Providence conducted flare measurements on 39 flares in the Barnett region from September 11th, 2023 to September 16th, 2023. The measurement summaries are provided in ***Table 1*** and ***Appendix A*** with the distribution of the measurements provided in ***Figure 2***. Overall efficiencies across the study were high, with 87% of the flares demonstrating a DRE above 98%.

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Appendix A: Results

Date/Time				Description		Conditions				Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (Local)	End Time (Local)	Company	Location	Distance (m)	Temp (°C)	RH (%)	WS (mph)	CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	9/11 -9/16	7:57 AM	8:13 AM			54	26	52	2-4	98.88	99.51	97.84	99.45	0.27	0.34	0.01	1.24	0.23	7.4	1.4	18.4	4.1	0.08	0.00	0.25	0.06	91.6	0.1	100.0	8.1
2		9:56 AM	10:12 AM			76	29	42	2-4	99.20	99.53	90.82	100.00	1.38	2.49	1.09	6.21	0.69	56.9	31.4	80.2	10.5	3.19	1.24	5.15	0.81	93.1	75.9	100.0	4.0
3		10:56 AM	11:11 AM			61	31	40	0-2	99.27	99.82	98.16	99.87	0.24	0.22	0.02	0.57	0.14	13.8	0.2	39.9	10.3	0.26	0.00	1.11	0.28	88.4	0.1	100.0	14.2
4		12:29 PM	12:45 PM			69	34	33	2-4	98.98	99.58	97.11	99.83	0.44	0.63	0.20	1.24	0.13	12.9	9.3	16.5	1.4	0.28	0.09	0.35	0.02	94.1	75.8	100.0	3.2
5		1:47 PM	2:04 PM			109	35	29	2-4	98.98	99.58	97.71	99.99	0.37	0.90	0.33	1.53	0.22	18.0	11.3	38.7	2.3	0.42	0.32	0.52	0.03	95.7	59.1	100.0	2.7
6		2:41 PM	2:56 PM			405	36	27	4-6	96.96	97.86	88.75	100.00	1.36	0.75	0.07	4.14	0.61	180.1	62.4	681.0	49.0	1.29	0.12	4.99	0.76	80.8	0.1	100.0	11.7
7		8:15 AM	8:31 AM			97	18	77	2-4	99.40	99.79	94.00	100.00	0.65	1.50	0.69	2.35	0.22	147.9	87.4	182.4	17.2	3.91	1.19	5.24	0.78	95.5	49.4	100.0	2.8
8		9:30 AM	9:45 AM			136	19	77	2-4	98.40	99.09	96.49	100.00	0.74	0.98	0.05	1.58	0.19	101.7	18.2	149.0	19.3	1.85	0.07	2.63	0.36	95.1	74.3	100.0	2.7
9		11:18 AM	11:33 AM		I	116	20	79	2-4	98.61	99.23	96.54	100.00	0.80	1.22	0.78	1.97	0.20	95.7	76.2	125.2	6.7	2.50	1.82	3.08	0.26	95.4	82.9	100.0	2.1
10		12:26 PM	12:42 PM			124	19	82	2-4	98.34	99.05	95.76	99.91	0.58	0.69	0.21	1.28	0.21	28.8	13.6	67.4	7.2	0.45	0.12	0.82	0.16	96.0	70.6	100.0	2.1
11		1:14 PM	1:30 PM			90	20	78	2-4	98.67	99.31	96.83	100.00	0.63	0.80	0.05	1.53	0.27	31.3	3.1	53.3	9.3	0.65	0.01	1.37	0.29	92.4	35.1	100.0	6.5
12		3:11 PM	3:28 PM			116	20	80	2-4	99.99	99.99	98.63	100.00	0.27	4.30	1.28	9.56	1.35	76.5	33.6	133.8	18.4	2.41	0.50	8.43	1.20	90.2	47.7	100.0	5.0
13		9:09 AM	9:17 AM			17	20	82	0-2	97.88	98.66	92.09	99.29	0.73	0.48	0.15	1.01	0.15	0.9	0.3	1.7	0.3	0.02	0.00	0.04	0.01	90.8	0.1	100.0	8.5
14		10:03 AM	10:18 AM			21	20	82	0-2	98.07	98.82	93.01	99.56	0.97	0.49	0.11	1.23	0.16	0.5	0.1	1.9	0.5	0.01	0.00	0.02	0.01	95.0	65.4	100.0	2.9
15		12:34 PM	12:50 PM			38	22	92	0-2	98.57	99.23	93.14	100.00	0.66	0.51	0.07	1.66	0.22	3.0	0.6	8.1	1.1	0.07	0.00	0.16	0.03	84.3	0.1	100.0	12.4
16		1:38 PM	1:40 PM			37	26	68	2-4	93.91	95.28	85.94	99.79	3.15	0.07	0.04	0.28	0.04	0.3	0.0	1.0	0.2	0.00	0.00	0.02	0.00	50.1	0.1	100.0	32.1
17		2:09 PM	2:24 PM			41	28	45	0-2	97.37	98.23	95.35	98.89	0.46	0.23	0.15	0.78	0.06	0.7	0.3	1.4	0.2	0.01	0.01	0.03	0.00	93.1	75.1	100.0	4.1
18		4:43 PM	4:58 PM			23	31	51	0-2	98.23	98.95	95.91	99.75	0.63	0.21	0.09	0.51	0.06	0.9	0.2	1.7	0.3	0.02	0.01	0.04	0.01	96.2	39.5	100.0	3.1
19		10:39 AM	10:53 AM			94	31	29	0-2	98.11	98.80	92.86	100.00	1.17	0.93	0.43	1.74	0.28	11.7	8.9	32.9	1.5	0.25	0.18	0.35	0.03	95.4	44.2	100.0	3.3
20		12:53 PM	1:08 PM			32	33	36	0-2	95.10	96.29	84.81	99.75	4.41	0.06	0.03	0.12	0.01	0.6	0.0	1.0	0.2	0.01	0.00	0.01	0.00	91.7	0.1	100.0	8.4
21		1:21 PM	1:36 PM			46	32	36	0-2	98.89	99.49	96.33	100.00	0.49	0.95	0.20	2.51	0.31	3.6	0.5	8.4	0.7	0.07	0.00	0.14	0.02	86.5	40.7	100.0	8.7
22		1:58 PM	2:13 PM			44	34	30	0-2	99.31	99.74	90.77	99.99	0.88	0.02	0.01	0.05	0.01	0.9	0.1	1.3	0.2	0.00	0.00	0.01	0.00	85.5	32.7	100.0	8.4
23		2:52 PM	3:07 PM			42	35	27	2-4	98.43	99.11	85.65	99.83	1.80	0.05	0.02	0.66	0.04	0.4	0.0	1.0	0.2	0.00	0.00	0.01	0.00	78.0	0.1	100.0	21.2
24		8:25 AM	8:41 AM			24	21	84	0-2	97.28	98.15	93.97	98.72	0.60	0.68	0.49	0.90	0.08	1.6	0.7	2.0	0.2	0.03	0.02	0.04	0.00	95.1	83.4	100.0	2.5
25		9:27 AM	9:43 AM			10	27	63	2-4	98.21	98.94	96.60	99.98	0.49	0.73	0.23	1.28	0.21	0.3	0.1	1.2	0.2	0.01	0.00	0.05	0.01	92.4	60.2	100.0	4.5
26		10:09 AM	10:40 AM			35	24	71	2-4	98.33	99.04	96.13	99.58	0.57	0.55	0.11	1.07	0.17	1.3	0.0	2.2	0.4	0.01	0.00	0.03	0.01	67.0	0.1	100.0	21.9
27		12:22 PM	12:36 PM			43	29	60	0-2	98.22	98.89	85.50	100.00	1.82	1.47	0.59	4.11	0.57	16.6	7.8	23.1	2.7	0.66	0.21	1.07	0.19	90.7	19.4	100.0	5.5
28		1:05 PM	1:21 PM			52	34	40	0-2	98.65	99.31	96.87	99.66	0.38	0.26	0.02	0.90	0.15	14.3	0.3	32.7	8.2	0.27	0.00	0.91	0.20	88.8	0.1	100.0	13.0
29		2:15 PM	2:30 PM			69	33	49	2-4	97.81	98.60	93.79	100.00	1.27	2.25	0.86	7.96	0.91	39.9	22.2	64.7	6.7	1.60	0.62	3.59	0.45	89.9	53.6	100.0	5.7
30		3:24 PM	3:41 PM			30	30	49	2-4	98.71	99.35	96.51	100.00	0.50	0.65	0.13	1.34	0.19	2.8	0.5	4.3	0.8	0.04	0.00	0.08	0.02	76.6	0.1	100.0	14.3
31		8:45 AM	9:00 AM			27	21	68	0-2	98.03	98.79	89.51	99.64	1.12	0.21	0.12	0.44	0.07	2.8	1.1	4.2	0.6	0.05	0.03	0.08	0.01	97.2	86.5	100.0	1.9
32		9:05 AM	9:40 AM			22	21	68	0-2	95.80	96.89	84.78	99.13	2.92	0.07	0.05	0.11	0.01	1.6	1.2	2.3	0.2	0.02	0.01	0.03	0.00	97.0	88.6	100.0	1.3
33		9:50 AM	10:24 AM			19	22	65	0-2	97.77	98.57	89.12	99.98	2.00	0.50	0.06	1.18	0.27	2.0	1.1	3.0	0.5	0.03	0.01	0.06	0.01	95.7	72.1	100.0	2.1
34		10:51 AM	11:06 AM			25	22	65	2-4	98.36	99.07	97.46	99.29	0.30	0.19	0.09	0.48	0.06	2.0	0.9	2.7	0.4	0.03	0.02	0.05	0.01	95.3	82.9	100.0	2.4
35		11:10 AM	11:25 AM			25	22	65	2-4	98.47	99.16	94.52	99.49	0.70	0.25	0.05	0.79	0.15	0.2	0.1	0.7	0.1	0.00	0.00	0.00	0.00	75.2	31.1	100.0	11.1
36		11:52 AM	12:07 PM			45	24	61	0-2	98.46	99.15	92.84	99.64	0.62	0.10	0.03	0.49	0.06	3.2	0.4	6.4	1.3	0.03	0.00	0.07	0.02	85.0	0.1	100.0	15.8
37		12:22 PM	12:37 PM			15	33	40	0-2	98.16	98.89	96.34	99.73	0.69	1.63	0.69	4.72	0.54	0.5	0.1	0.8	0.2	0.01	0.00	0.02	0.00	89.0	4.6	100.0	8.3
38		1:10 PM	1:27 PM			29	33	41	0-2	98.24	98.96	95.03	99.99	0.54	0.45	0.11	1.36	0.22	2.1	1.0	3.1	0.3	0.03	0.01	0.05	0.01	88.4	44.9	100.0	6.1
39		1:29 PM	1:43 PM		L	34	33	41	0-2	96.24	97.27	89.45	99.84	1.29	0.91	0.07	1.65	0.28	0.3	0.0	1.0	0.2	0.00	0.00	0.01	0.00	51.5	0.1	100.0	29.2

Table 2: Complete Mantis Results.

Appendix B: Validation of the VISR method

Precision and Accuracy of the VISR Method for Flare Monitoring

Extended Abstract: ME92
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Introduction

Industrial flares represent a large category of air emission sources for Volatile Organic Compounds (VOC), air toxics, and greenhouse gases (GHG)[1-4]. Depending on their combustion efficiency (CE), the emissions of these air pollutants can be significantly different. Despite the large contribution of flares to air emission inventories, flares are the only source category for which no EPA test or monitoring methods can be applied to directly measure their efficiency or emission rates. As a result, flare emissions in air emission inventories may carry significant uncertainties.

A method based on Video Imaging Spectral Radiometry (VISR) has been developed for testing or continuously monitoring combustion efficiency (CE) of industrial flares[5]. To validate the VISR method, tests were conducted at flare test facilities of Zeeco, Inc. (Zeeco) and John Zink Hamworthy Combustion (John Zink), both located in Tulsa, Oklahoma, in September and October 2016, respectively. The test at Zeeco included both an air assisted flare and a steam assisted flare. Twenty-eight flare conditions were tested, 14 for the air flare and 14 for the steam flare. This test is referred to as the "Zeeco Test" in this paper.

The test at John Zink was part of a program sponsored and organized by the Petroleum Environmental Research Forum (PERF), an industry consortium. PERF project 2014-10 Direct Monitoring of Flare Combustion Efficiency was created and funded by participating PERF companies to provide a test platform for various developers/vendors of flare remote sensing technologies (Invitees) to participate in a blind test to evaluate the effectiveness of each technology. The blind test was administered by John Zink. Testing began on October 17th, 2016 and continued for 10 days, concluding on October 27th, 2016. The flare tip used was the John Zink model EEF-QSC-36, which was the same flare tip used during the 2010 TCEQ Flare Study[4]. A test protocol was developed which identified a series of test conditions to evaluate various factors that could affect flare CE measurement. Only limited logistical and environmental factors were shared with the Invitees (i.e., distance from the flare, view angle with respect to flame orientation due to wind, sun in/out of the field of view, daytime/nighttime testing). Information regarding flare operations such as the type of fuel gas used, firing rates, steam rates or any other flare operating parameters was concealed from Invitees. A total of 45 test points was evaluated over the 10 days of testing. Extractive sampling was performed on each test point as the control method for flare CE measurement. The results of the extractive sampling were not provided to Invitees until Invitees submitted their won results based on their respective measurement technology. This test is referred to as the "PERF Test" in this paper.

In this paper, the precision and accuracy of the VISR method are evaluated based on the test campaigns described above.

Methods and experimental setup

The VISR flare monitor is a remote monitoring device that can be positioned at any distance as long as the flare to be monitored is in the line of sight and there are a sufficient number of pixels of the flare flame image in the VISR monitor. The distances from flare to the VISR monitor in the experiments reported here were in the range of 174 feet to 650 feet. To evaluate the performance of the VISR method, an extractive sampling system was used as a reference method. A sample extraction apparatus was suspended by a crane over the flare plume to extract combustion product gases. The sample was transported through a heated sampling line to a sample manifold in a testing trailer. The sample manifold was connected to analyzers for oxygen (O_2), carbon dioxide (CO_2), carbon monoxide (CO), and hydrocarbon (HC). The methods for measuring O_2, CO_2, CO, and HC were EPA Method 3A, 3A, 10, and 25A, respectively. The level of O_2 was used to confirm that the sampling probe was in the flare plume. The concentrations of CO_2, CO, and HC were used to calculate flare CE per method used in the 2010 TCEQ flare study[3].

These test campaigns covered a wide range of process conditions: two steam flares and one air flare; multiple vent gas compositions (natural gas, propane, propylene, hydrogen, in pure form or mixed with nitrogen; vent gas flow range from 10 lb/hr to 10,000 lb/hr; various steam and air assist levels resulting in combustion zone net heating value (NHVcz) in a range of 120 to 1,250 Btu/scf for the steam flares and net heating value dilution parameter (NHVdil) in a range of 6.7 to 244 Btu/ft^2 for the air flare.

The test campaigns also covered a wide range of environmental conditions: distance ranging from 174 ft. to 650 ft.; different wind speed and direction (crosswind, wind oriented towards VISR device, and wind oriented away from VISR device); daytime vs. nighttime; various sky conditions (blue sky, cloudy, moving clouds); the Sun in or out of field of view; rain, and fog.

Results and Discussions

Precision

Precision is a measure of how the results of multiple measurements by the same method scatter while the target of the measurement holds steady. This is difficult to assess for flare measurements because even when the flare operating conditions are held steady (as they were in each test point of the PERF Test), the flare CE may change due to changes in environmental conditions. Analyte spiking or quadruplet sampling described in EPA Method 301 would help to isolate the measurement method precision from the fluctuation of the target itself[6]. However, these methods are not feasible for flare measurement. Nevertheless, the measurement precision can still be evaluated using the data from the PERF test. For each PERF test condition, 4 segments of measurement were made by the extractive method and 3 segments of measurement were made by VISR while the flare operating conditions were held constant (although flare CE did fluctuate due to changes in environmental conditions). The standard deviation (SD) and relative standard deviation (RSD) can be calculated based on these replicate measurements. **Table 1** is a summary of the SD and RSD for both the VISR method and the extractive method used in the PERF Test. As shown in **Table 1**, the RSD for the VISR method is in a range of 0.07% to 1.98% with an average of 0.62%. The variation of the VISR method appears to be slightly better than the extractive method from the perspective of both the average and the range of the RSD values, suggesting that the precision of VISR is at least as good as the extractive method. Note that in both cases, the variation due to changing environmental conditions is included in the RSD as there is no practical method to separate it. Despite the inclusion of environmental changes, the RSD is more than an order of magnitude smaller than 20% as required in EPA Method 301 (Section 9.0)[6]. If a more stringent criteria is used in which the 20% limit on RSD is applied to the most relevant range of 90-100 % CE measurement (i.e., in the span of 10 % CE measurement), the criteria would be SD < 2 % CE (20% of 10% = 2 % CE). As shown in **Table 1**, the highest SD is 1.84 measured as % CE, which is lower than the SD of 2 % CE measurement and therefore satisfies the more stringent criteria.

Table 1. Relative Standard Deviation (RSD) of VISR and extractive method per PERF Test

Method	CE Avg.	CE Range	SD Avg.	SD Range	RSD Avg.	RSD Range
VISR	96.47	80.61-99.91	0.59	0.07-1.84	0.62%	0.07-1.98%
Extractive	96.41	83.50-100.00	0.83	0.00-2.61	0.88%	0.00-2.72%

The Zeeco Test did not include multiple replicated measurements under each test condition. Therefore, a precision analysis is not performed on that data.

Accuracy

The accuracy of the VISR method is evaluated based on the Zeeco Test and PERF Test. In these two tests, the flare CE was measured by both the VISR method and the extractive method. The extractive method was used as the control (reference) method. Strictly speaking, what can be assessed is the agreement between the two methods, not the accuracy of either method because the true flare CE is unknown. The agreement between the two methods can be evaluated using a statistical method. One such method is to use t-test on the differences between the paired CE measurements by VISR and extractive methods. This method is the same as the method used in EPA Method 301 to determine if there is a difference caused by different sample storage time[6] (it should be noted that the methods for bias described in Method 301 are not directly applicable because they are specifically designed for analyte/isotopic spiking or quadruplet sampling systems, which are not feasible for flare measurement). The value of the t-statistic is calculated using the following equation.

$$t = \frac{|d_m|}{\frac{SD_d}{\sqrt{n}}}$$

Where d_m and SD_d are the mean and the standard deviation of the difference of the paired samples (VISR and extractive sample), and n is the total number of samples. The resulted t-statistic value is compared to the critical value of the t-statistic with a 95 percent confidence level and n-1 degree of freedom. If the resulted t-statistic value is less than the critical value, the difference between the VISR method and the extractive method is not statistically significant, i.e., the two methods are statistically the same. The results of the t-statistical analysis for both Zeeco and PERF tests are summarized in **Table 2**. The number of samples (tests) in **Table 2** is less than the number of tests actually conducted because some tests were designed for other purposes (e.g., smoke test) and they are not included in the evaluation of the agreement between VISR and extractive methods.

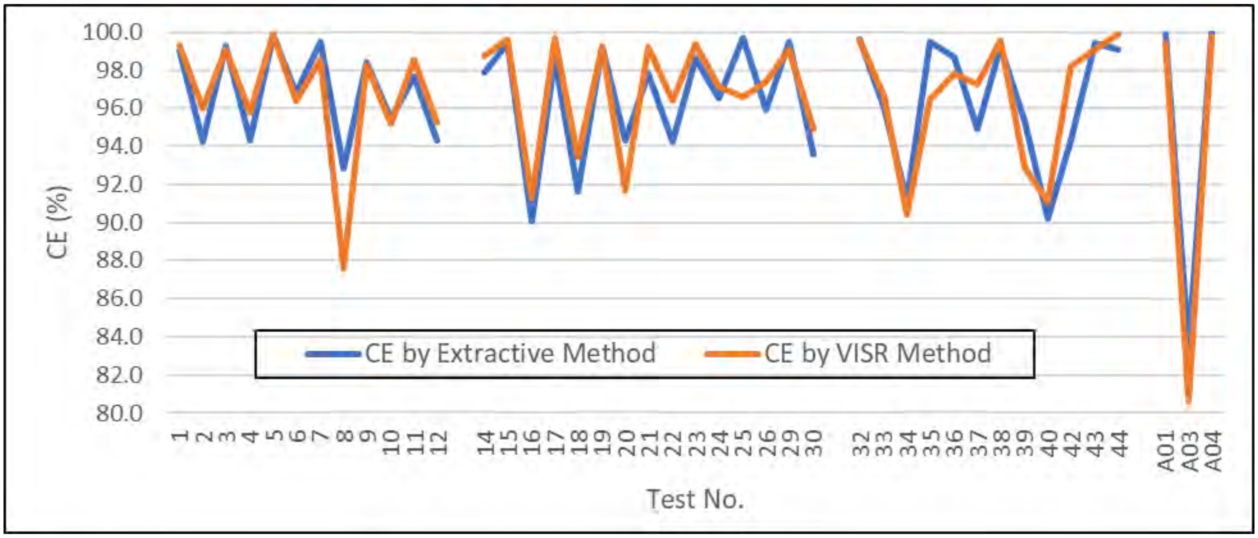
Table 2. t-Test to determine if the VISR method is different from the extractive method

	Zeeco Test (Steam Flare)	**Zeeco Test (Air Flare)**	**PERF Test**
No. of Samples, n	11	9	42
Mean Difference, d_m (% CE)	0.30	-0.21	0.07

Standard Deviation, SD_d (% CE)	1.32	0.65	1.69
t-Statistic Value	0.756	0.967	0.254
Degree of Freedom	10	8	41
t_95 Critical Value	2.228	2.306	2.020
Statistically Different?	No	No	No

As demonstrated in **Table 2**, statistically there is no difference between the flare CE measured by the VISR method and by the extractive method. The agreement between the two measurement methods can also be illustrated in **Figure 1** using the results from the PERF Test.

Figure 1. Flare CE measured by VISR method and extractive method – PERF Test results



Conclusion

Industrial flares can now be measured or continuously monitored by the VISR method for their performance, i.e., combustion efficiency (CE). The VISR method is a remote sensing method and can be deployed easily and practically. The VISR method transforms flare testing/monitoring from most difficult task (impossible in many cases) to a task that is easier than most conventional air emission testing methods. With the significant potential benefits that the VISR method can bring, it is important to characterize and understand the precision and accuracy of this method.

Through a large number of tests under various process and environmental conditions, a high precision and accuracy have been demonstrated for the VISR method. The relative standard deviation (RSD) is in the range of 0.07-1.98% with an average RSD of 0.62% for flare CE in the range from 80 to 100%. The average RSD of 0.62% is more than an order of magnitude smaller than the minimum precision target of 20% RSD set in EPA Method 301. The highest SD is only 1.84 measured as % CE.

The flare CE measured by the VISR method is in excellent agreement with the flare CE measured by the extractive method. The mean difference between the two methods is in the range of -0.21 to 0.30 measured in % CE. The t-statistic value in each of the three test groups are well below its corresponding t-test critical value, passing the t-test with a substantial margin. Keep in mind that the extractive method is suitable only in research. It is virtually impossible to deploy the extractive method to elevated flares at industrial production facilities. Having a method that can be easily deployed to industrial sites and produce highly time-resolved and accurate flare measurement results is a significant advancement.

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6. U.S. EPA, *Code of Federal Regulations*, Title 40, Part 63, Appendix A, Method 301, 2018.

Appendix C: Combustion Efficiency Versus Destruction Efficiency

With respect to emissions calculations or GHG reporting, it is important to consider the difference between combustion efficiency (CE) and destruction efficiency (DE). The VISR method measures CE, which is a measure of the efficiency of the flame to convert hydrocarbons into carbon dioxide and water. If the combustion efficiency is 100%, then all of the hydrocarbons have been oxidized all the way to carbon dioxide, leaving no hydrocarbons in the post combustion plume. CE will be reduced as the percentage of hydrocarbon in the post combustion plume increases. Destruction efficiency is a measure of the percentage of a compound that is destroyed (IE converted into another form), but not necessarily oxidized to the ultimate combustion product of carbon dioxide and water. In this case, it represents the percentage of hydrocarbons destroyed. The hydrocarbons could be converted to carbon dioxide, carbon monoxide, soot or another compound. As a result, DE is typically higher than CE. For emission inventory purposes, flares are generally deemed to have a DE of 98%, meaning 98% of the hydrocarbons sent to the flare are converted into another form. There is no quantitative method to convert the VISR CE data to DE, however we do have some points of reference. The US EPA Refinery Sector Rule (40 CFR 63.670 (r) equates a CE of 96.5% to a DE of 98%. The rule references the John Zink combustion handbook (Baukal, 2001).

In addition, there have been two major studies which have measured both CE and DE with extractive sampling: the 2010 TCEQ Study and the 2016 PERF Study. Both of these studies were conducted at John Zink's research facility in Tulsa, Oklahoma. Taken collectively, these studies provide 71 individual measurements of CE and DE. *Figure 8* below shows the relationship between CE and DE from these two studies.

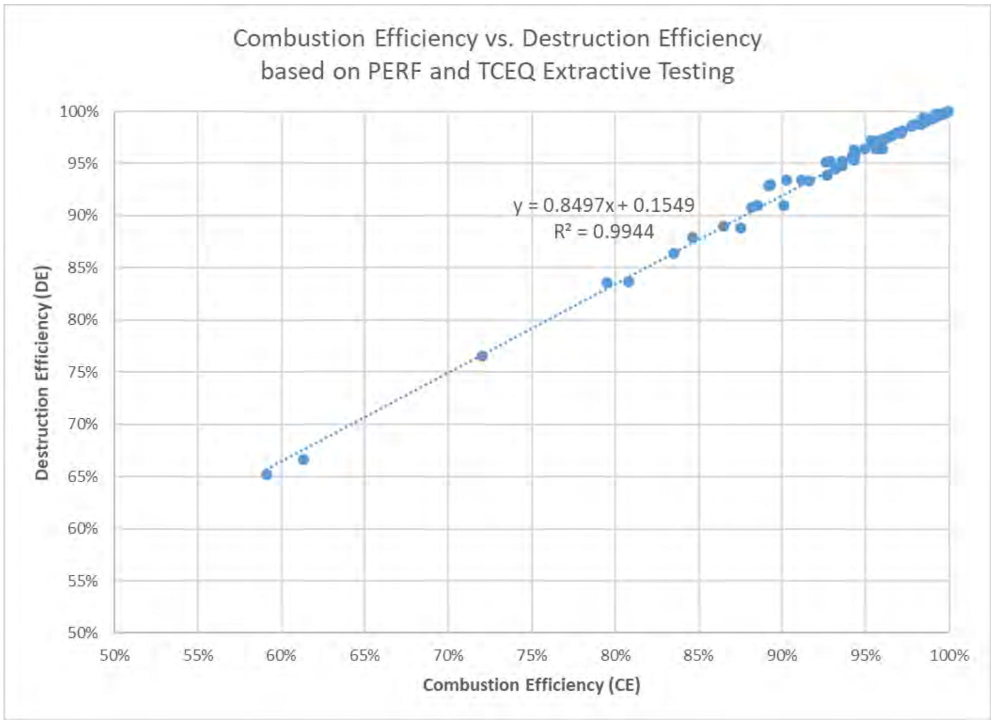

Figure 17. CE vs DE from extractive sampling during PERF and VISR studies.

As demonstrated by the chart, the relationship between DE and CE is quite linear. The fit equation to this data has an R^2 of 0.99. Equation 2 below can be used to convert CE to DE using this correlation:

$$DE\ (\%) = CE\ (\%) * 0.8497 + 0.1549$$

Equation 2

It should be noted that when SI is high and CE appears to be low, the destruction efficiency (DE) may still be high as the hydrocarbons are combusted into soot instead of oxidizing to the ultimate combustion products of water and CO_2. The CE-DE relationship shown in *Figure 8* is established under no smoke conditions. There has not been sufficient study on a similar CE-DE relationship when there is significant smoke in the flare. This equation will be valid for CE within a range of 60% to 99.4%. Above 99.4%, the DE will be capped at 100%. Below 60%, there is no extractive data available to extend the correlation.

PROVIDENCE PHOTONICS

[redacted]

VISR Field Study

Final Report | Revision 1.0

April 2022

[redacted]

NORTH DAKOTA

PREPARED BY
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Introduction

Providence Photonics, LLC (Providence) has developed a method to remotely measure the performance of an industrial flare using Video Imaging Spectral Radiometry (VISR). The VISR method provides five flare performance metrics: combustion efficiency (CE), smoke index (SI), flame stability (FS), flame footprint (FF), and fractional heat release (FH).

Providence conducted a field campaign using VISR at various [redacted] facilities in North Dakota from April 4th, 2022 to April 8th, 2022. A total of 92 individual flare measurements were performed. In addition to the VISR measurements, an mp4 video was captured for each flare using a FLIR GF320 optical gas imaging camera. This report summarizes the data and findings from the campaign.

Background

The VISR method utilizes a multi-spectral midwave infrared imager to measure relative concentrations of combustion gases. The method was designed to be a continuous and autonomous remote flare monitor, but in this study it was deployed as a mobile technology for a short-term measurement. ***Figure 1*** below shows the VISR device deployed at a [redacted] facility in North Dakota. The VISR device and related equipment was powered from the 12V battery system of the vehicle.

Figure 1: VISR device deployed at a [redacted] facility in North Dakota.

Results

The results from VISR measurements are tabulated in **Appendix A** and a summary is provided in *Table 1 below*.

Table 1: Summary VISR Results.

ID	Site Description	Flare Description	Distance (m)	Temp (°C)	RH (%)	Avg Wind Speed (mph)	FLIR Video	CE Avg (%)	DRE Avg (%)	SI Avg	FF Avg (m2)	FH Avg (MMBT	FS Avg (%)
1	[redacted]	High Pressure	46	3	72	4 to 6	MOV_2332.mp4	98.12	98.86	1.0	0.4	0.004	89.1
2		Low Pressure	54	3	72	4 to 6	MOV_2334.mp4	99.68	99.94	0.3	0.3	0.004	96.8
3		High Pressure	38	9	53	4 to 6	MOV_2337.mp4	99.50	99.93	0.8	1.4	0.021	95.5
4		Low Pressure	46	9	53	4 to 6	MOV_2338.mp4	99.05	99.63	0.7	1.4	0.025	96.6
5		High Pressure	44	8	59	8 to 10	MOV_2339.mp4	99.76	99.95	0.2	3.4	0.051	96.2
6		Low Pressure	61	8	59	8 to 10	MOV_2340.mp4	99.35	99.83	0.6	0.5	0.004	93.7
7		High Pressure	45	10	53	4 to 6	MOV_2341.mp4	99.54	99.92	0.5	0.6	0.007	81.8
8		High Pressure	42	11	50	6 to 8	MOV_2342.mp4	99.03	99.61	0.4	1.8	0.028	93.6
9		Low Pressure	53	11	50	6 to 8	MOV_2344.mp4	99.36	99.86	0.4	0.9	0.011	91.0
10		Low Pressure	44	14	39	12 to 14	MOV_2348.mp4	98.90	99.52	0.6	0.7	0.010	93.4
11		HP/LP Assisted	49	14	38	14 to 16	MOV_2351.mp4	97.66	98.47	0.2	5.5	0.088	97.4
12		High Pressure South	49	14	38	14 to 16	MOV_2354.mp4	98.59	99.23	1.5	3.4	0.092	92.5
13		Low Pressure South	52	14	38	14 to 16	MOV_2356.mp4	99.46	99.89	0.7	0.1	0.001	92.1
14		High Pressure North	38	14	38	14 to 16	MOV_2358.mp4	98.88	99.50	0.1	0.3	0.003	92.6
15		Low Pressure North	32	14	38	14 to 16	MOV_2359.mp4	99.49	99.85	0.3	0.1	0.001	89.4
16		High Pressure	37	18	32	10 to 12	MOV_2362.mp4	98.04	98.79	0.4	1.2	0.020	89.9
17		Low Pressure	45	18	32	10 to 12	MOV_2363.mp4	98.59	99.26	0.7	0.1	0.001	94.5
18		High Pressure	34	19	32	12 to 14	MOV_2365.mp4	98.90	99.51	0.6	0.2	0.002	95.2
19		Low Pressure	38	19	32	12 to 14	MOV_2366.mp4	98.46	99.15	0.1	0.5	0.007	93.3
20		High Pressure	37	19	30	8 to 10	MOV_2367.mp4	98.68	99.34	0.2	3.2	0.056	96.7
21		Low Pressure	45	19	30	8 to 10	MOV_2368.mp4	99.46	99.87	0.7	0.2	0.002	94.9
22		Dual HP/LP	44	6	55	8 to 10	MOV_2369.mp4	99.57	99.91	0.4	0.9	0.025	87.8
23		Low Pressure	68	6	55	12 to 14	MOV_2371.mp4	99.48	99.92	0.1	1.3	0.020	95.9
24		Dual HP/LP	43	7	49	14 to 16	MOV_2374.mp4	98.83	99.45	0.6	0.2	0.001	90.8
25		Dual HP/LP	48	8	42	8 to 10	MOV_2375.mp4	99.24	99.77	1.0	0.3	0.002	91.5
26		Low Pressure	46	7	44	14 to 16	MOV_2380.mp4	98.80	99.36	0.2	0.4	0.004	77.4
27		Dual HP/LP	42	7	42	18 to 20	MOV_2385.mp4	88.30	90.52	0.3	5.8	0.100	95.2
28		Dual HP/LP	42	8	43	18 to 20	MOV_2390.mp4	93.40	94.85	0.1	1.7	0.021	82.9
29		Low Pressure	46	8	44	18 to 20	MOV_2392.mp4	99.66	99.94	0.2	0.8	0.009	91.1
30		Dual HP/LP	37	10	41	16 to 18	MOV_2396.mp4	98.43	99.11	0.4	0.5	0.005	85.6
31		Low Pressure	43	10	41	22 to 24	MOV_2397.mp4	99.38	99.87	1.5	6.3	0.130	93.0
32		High Pressure	48	9	42	18 to 20	MOV_2398.mp4	99.67	99.95	0.3	1.0	0.013	89.8
33		Dual HP/LP	43	8	48	18 to 20	MOV_2400.mp4	96.17	97.20	0.2	5.5	0.088	95.7
34		Dual HP/LP	49	7	63	10 to 12	MOV_2401.mp4	99.88	99.95	0.2	12.4	0.257	97.2
35		High Pressure	50	7	68	4 to 6	MOV_2402.mp4	99.31	99.80	0.6	0.7	0.009	85.9
36		Low Pressure	40	7	68	4 to 6	MOV_2403.mp4	99.66	99.95	0.5	0.9	0.012	94.5
37		High Pressure	32	9	61	8 to 10	MOV_2404.mp4	99.52	99.91	0.8	0.2	0.003	92.7
38		Low Pressure	37	9	61	8 to 10	MOV_2405.mp4	99.40	99.89	0.5	0.6	0.007	96.2
39		Dual HP/LP	55	7	68	6 to 8	MOV_2406.mp4	99.23	99.78	0.2	1.0	0.010	85.7
40		High Pressure	52	6	67	8 to 10	MOV_2407.mp4	98.35	99.06	1.6	3.1	0.072	94.4
41		Low Pressure	60	6	67	8 to 10	MOV_2408.mp4	99.56	99.88	0.3	0.5	0.005	89.4
42		Dual HP/LP	68	2	79	10 to 12	MOV_2410.mp4	98.51	99.13	0.6	0.9	0.018	90.3
43		High Pressure	37	1	78	12 to 14	MOV_2411.mp4	99.26	99.71	0.4	0.8	0.009	88.9
44		Low Pressure	60	1	78	12 to 14	MOV_2412.mp4	97.88	98.66	0.1	1.1	0.011	94.7
45		Low Pressure	48	3	75	10 to 12	MOV_2413.mp4	98.87	99.48	0.9	0.3	0.004	95.9
46		Dual HP/LP	58	3	73	16 to 18	MOV_2416.mp4	98.66	99.31	0.5	9.0	0.181	97.7
47		Dual HP/LP	46	9	57	16 to 18	MOV_2418.mp4	97.12	97.96	0.8	0.6	0.008	86.5
48		Dual HP/LP	75	9	48	10 to 12	MOV_2419.mp4	97.37	98.22	0.2	7.2	0.134	89.1
49		Dual HP/LP	37	11	49	18 to 20	MOV_2420.mp4	98.55	99.23	1.2	0.3	0.003	86.4
50		High Pressure	40	7	43	12 to 14	MOV_2422.mp4	99.10	99.68	0.1	6.6	0.131	97.0
51		Dual HP/LP	43	12	43	30 to 32	MOV_2423.mp4	99.18	99.74	2.0	0.1	0.001	96.2
52		Low Pressure	50	8	29	26 to 28	MOV_2424.mp4	99.41	99.83	0.8	0.2	0.002	92.3
53		High Pressure	36	8	29	26 to 28	MOV_2425.mp4	99.27	99.80	0.1	0.1	0.000	82.3
54		Dual HP/LP	58	-1	68	10 to 12	MOV_2426.mp4	98.75	99.40	0.3	1.6	0.020	90.8
55		Dual HP /LP	49	-1	67	18 to 20	MOV_2427.mp4	98.43	99.10	0.6	1.6	0.037	86.2
56		Low Pressure	28	-2	72	14 to 16	MOV_2428.mp4	99.10	99.67	0.1	0.7	0.010	94.2
57		Dual HP/LP	61	-1	79	18 to 20	MOV_2429.mp4	97.10	98.00	0.2	2.2	0.031	80.9
58		Dual HP/LP	53	2	70	12 to 14	MOV_2430.mp4	99.13	99.63	0.4	1.3	0.018	85.9
59		Low Pressure	40	5	54	20 to 22	MOV_2432.mp4	99.08	99.67	0.2	0.9	0.013	92.3
60		Dual HP/ LP	70	5	50	16 to 18	MOV_2433.mp4	96.31	97.31	0.4	6.5	0.118	74.6
61		Dual HP/LP	42	3	51	18 to 20	MOV_2434.mp4	99.57	99.91	0.5	0.2	0.002	81.3
62		Low Pressure North	37	5	45	18 to 20	MOV_2435.mp4	99.00	99.55	0.5	0.7	0.010	91.5
63		Low Pressure South	43	5	45	18 to 20	MOV_2437.mp4	99.36	99.79	0.6	0.2	0.001	84.6
64		High Pressure	41	5	45	18 to 20	MOV_2438.mp4	99.03	99.56	3.0	0.6	0.009	95.0
65		High Pressure North	34	6	38	22 to 24	MOV_2439.mp4	99.68	99.94	0.3	0.9	0.014	90.6
66		High Pressure South	48	6	38	22 to 24	MOV_2440.mp4	99.75	99.95	0.6	0.9	0.014	89.8
67		Low Pressure	58	6	38	22 to 24	MOV_2441.mp4	99.19	99.71	0.2	0.2	0.002	84.2
68		Low Pressure	31	6	41	20 to 22	MOV_2442.mp4	99.64	99.94	0.4	1.3	0.028	93.4
69		High Pressure	32	9	34	10 to 12	MOV_2443.mp4	98.80	99.42	0.4	0.7	0.009	91.7
70		Low Pressure	39	9	34	10 to 12	MOV_2444.mp4	99.27	99.80	0.3	0.6	0.008	87.8
71		Low Pressure	37	7	37	16 to 18	MOV_2445.mp4	98.57	99.23	0.6	0.3	0.003	87.7
72		Dual HP/LP	68	8	36	20 to 22	MOV_2446.mp4	98.48	99.14	0.3	7.0	0.137	87.9
73		Dual HP/LP	58	11	32	6 to 8	MOV_2451.mp4	98.02	98.78	0.3	1.2	0.013	80.3
74		Dual HP/LP	91	7	42	16 to 18	MOV_2452.mp4	98.73	99.34	1.2	22.6	0.842	96.8
75		Low Pressure	39	-2	66	0 to 2	MOV_2453.mp4	98.29	99.01	1.0	0.7	0.012	95.8
76		High Pressure	30	-2	66	0 to 2	MOV_2454.mp4	99.43	99.87	0.7	0.3	0.004	94.9
77		Dual HP/ LP	76	2	55	0 to 2	MOV_2455.mp4	96.73	97.58	0.6	30.0	0.288	94.1
78		Dual HP/LP	83	3	59	0 to 2	MOV_2459.mp4	95.02	96.23	0.2	6.1	0.100	87.1
79		Dual HP/ LP	57	8	42	0 to 2	MOV_2460.mp4	99.74	99.95	1.1	0.2	0.001	95.3
80		Dual HP/LP	112	10	29	0 to 2	MOV_2461.mp4	99.44	99.90	0.5	53.6	1.098	96.8
81		Dual HP/LP	112	10	29	0 to 2	MOV_2462.mp4	99.36	99.82	0.5	61.2	1.239	96.5
82		Dual HP/LP	167	12	25	6 to 8	MOV_2463.mp4	99.20	99.72	0.7	53.8	1.104	96.9
83		Low Pressure	50	11	26	4 to 6	MOV_2464.mp4	96.50	97.49	0.1	1.6	0.025	88.8
84		Low Pressure South	37	13	25	4 to 6	MOV_2466.mp4	99.60	99.91	0.3	0.6	0.008	95.1
85		Low Pressure North	36	13	25	4 to 6	MOV_2467.mp4	99.18	99.69	0.5	0.4	0.005	93.7
86		Low Pressure South	20	13	25	4 to 6	MOV_2468.mp4	99.52	99.91	0.2	0.1	0.001	94.9
87		Low Pressure	59	14	23	4 to 6	MOV_2469.mp4	99.78	99.94	0.8	0.5	0.004	92.4
88		Low Pressure	40	14	23	4 to 6	MOV_2470.mp4	99.70	99.95	0.9	0.4	0.003	96.5
89		High Pressure	50	13	21	2 to 4	MOV_2471.mp4	99.21	99.69	1.0	9.4	0.265	94.9
90		High Pressure	63	13	21	2 to 4	MOV_2472.mp4	99.21	99.76	0.2	1.1	0.009	90.4
91		Dual HP/LP	42	15	18	2 to 4	MOV_2474.mp4	98.90	99.52	0.2	2.0	0.034	96.6
92		Low Pressure	30	12	17	8 to 10	MOV_2475.mp4	99.14	99.72	0.6	0.4	0.004	87.2

Flare Performance Metrics

VISR provides five flare performance metrics at a 1-second data interval:

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%. CE should not be confused with Destruction and Removal Efficiency (DRE). The difference between these two metrics is discussed in **Appendix C**. While CE is directly measured by the VISR method, DRE is derived using correlations established through extractive sampling as discussed in **Appendix C**.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 2 indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the VISR imager. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the VISR imager in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this study the flame size was above the minimum number of pixels for all measurements performed.

The second important DQI is the Smoke Index level. As the smoke index increases above 2.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Extractive testing shows that SI values above 3.0 may cause a small negative bias on the CE measurement (< 1%) and SI values above 5 may cause a significant negative bias to CE, as confirmed by testing with an extractive sampling method as a control. Any data points with a smoke index above 3 were removed from the summary tables and **Appendix A** results.

Observations

The following sections describe observations and comparisons derived from the dataset.

Distribution of Flare DRE

The majority of flares measured (90%) had a DRE greater than 98%, and 84% had a DRE greater than 99%. ***Figure 2*** shows the distribution of flare DRE measurements across the entire dataset.

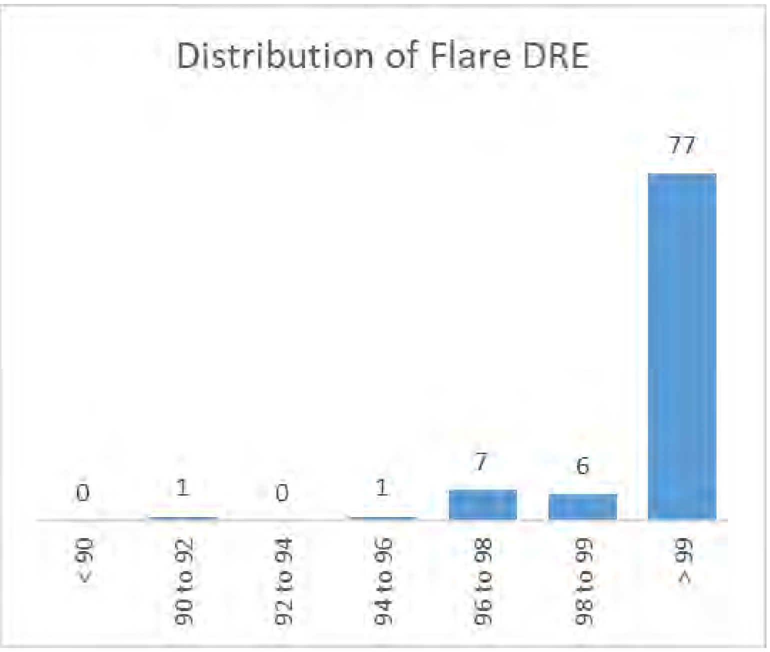

Figure 2: Distribution of Flare DRE measurements.

[redacted]

The lowest performing flare [redacted]
Figure 3 provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute measurement period was 90.82%.

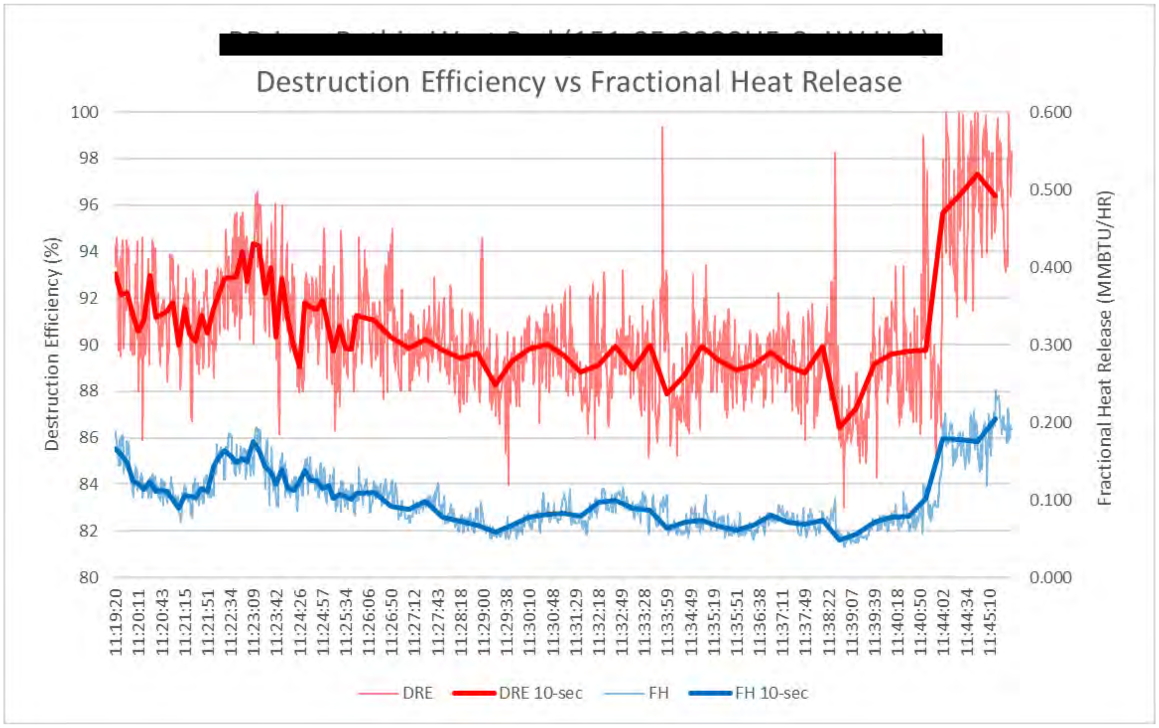

Figure 3: Destruction Efficiency vs. Fractional Heat Release for [redacted].

[redacted]

The flare with next lowest performance was the [redacted] [redacted]). ***Figure 4*** provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute period was 94.85%.

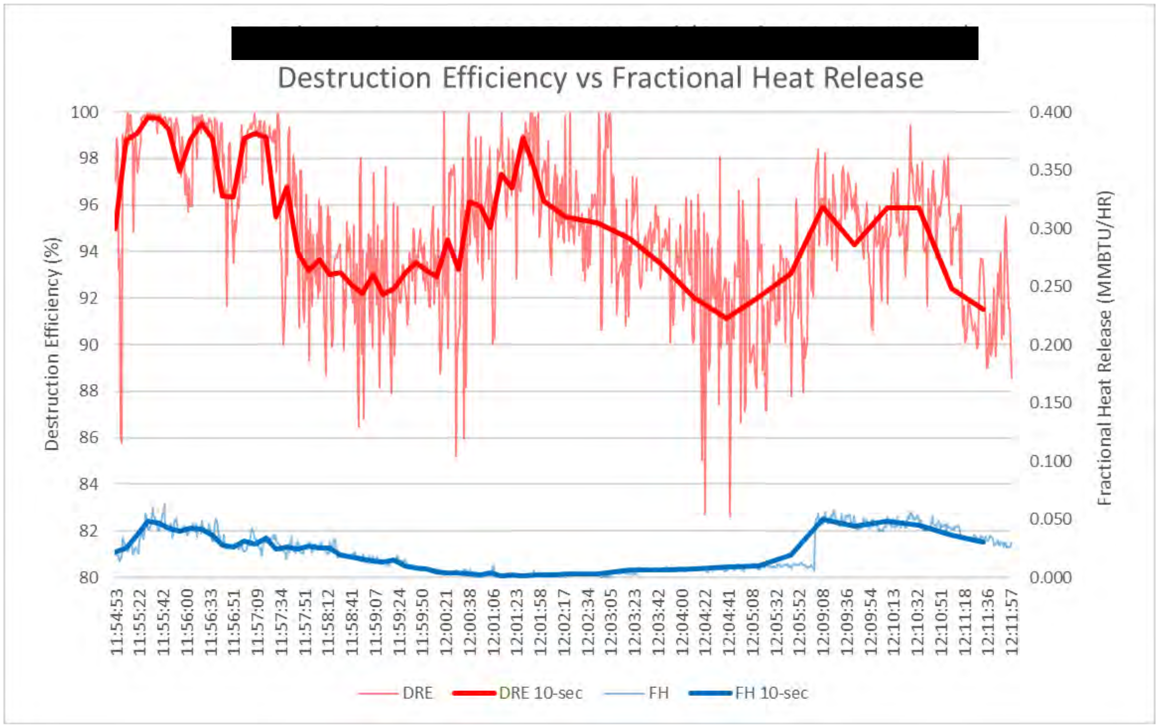

Figure 4: Destruction Efficiency vs. Fractional Heat Release for [redacted]

[redacted]

The flare with next lowest performance was the [redacted]-[redacted] ***Figure 5*** provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute period was 96.23%.

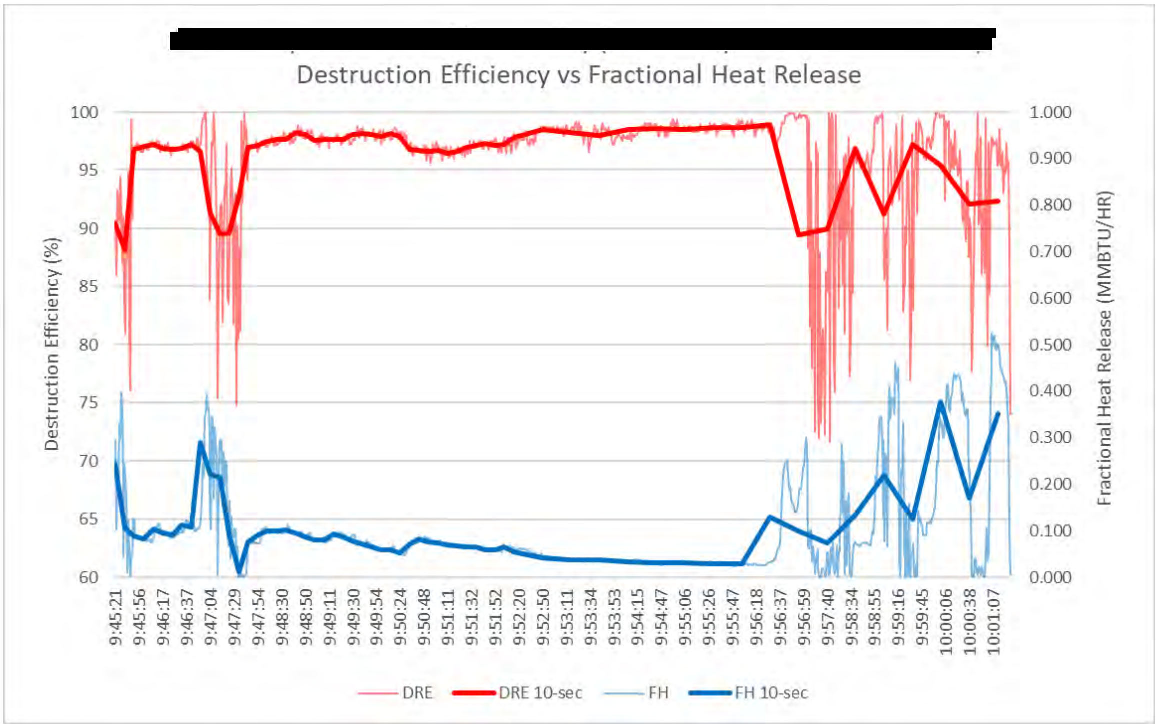
[redacted]

Figure 5: Destruction Efficiency vs. Fractional Heat Release and Smoke Index for [redacted]

Summary

In total, 92 flares across 67 sites were measured during the five-day study. The average DRE for all flares measured was 99.3%. Although there were a handful of flares with a DRE less than 98% (9 of 92), the majority of flares measured had a DRE which exceeded 99% (77 of 92). This data is consistent with prior studies in the area.

References

1. Yousheng Zeng, Jon Morris & Mark Dombrowski (2015) Validation of a new method for measuring and continuously monitoring the efficiency of industrial flares, Journal of the Air & Waste Management Association, 66:1, 76-86, DOI: 10.1080/10962247.2015.1114045

Appendix A: Results

Date/Time				Description				Conditions				FLIR Video	Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (Local)	End Time (Local)	Site Description	Latitude	Longitude	Flare Description	Distance (m)	Temp (°C)	RH (%)	Avg Wind Speed (mph)		CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	4/4/2022	8:04 AM	8:20 AM				High Pressure	46	3	72	4 to 6	MOV_2332.mp4	98.12	98.86	94.65	99.82	0.83	1.0	0.4	1.9	0.2	0.4	0.3	0.6	0.0	0.004	0.002	0.007	0.001	89.1	64.3	99.9	5.5
2	4/4/2022	8:23 AM	8:39 AM				Low Pressure	54	3	72	4 to 6	MOV_2334.mp4	99.68	99.94	98.53	99.99	0.16	0.3	0.2	1.1	0.1	0.3	0.2	0.7	0.0	0.004	0.002	0.006	0.001	96.8	42.6	100.0	4.0
3	4/4/2022	8:55 AM	9:10 AM				High Pressure	38	9	53	4 to 6	MOV_2337.mp4	99.50	99.93	98.90	99.87	0.16	0.8	0.4	1.1	0.1	1.4	1.1	1.7	0.1	0.021	0.016	0.027	0.001	95.5	86.7	100.0	2.3
4	4/4/2022	9:11 AM	9:26 AM				Low Pressure	46	9	53	4 to 6	MOV_2338.mp4	99.05	99.63	95.73	99.70	0.47	0.7	0.3	1.2	0.2	1.4	1.1	1.8	0.1	0.025	0.021	0.034	0.002	96.6	88.3	100.0	1.8
5	4/4/2022	9:40 AM	9:55 AM				High Pressure	44	8	59	8 to 10	MOV_2339.mp4	99.76	99.95	98.41	99.89	0.07	0.2	0.1	0.4	0.0	3.4	2.5	4.4	0.3	0.051	0.035	0.067	0.004	96.2	88.8	100.0	1.8
6	4/4/2022	9:56 AM	10:12 AM				Low Pressure	61	8	59	8 to 10	MOV_2340.mp4	99.35	99.83	92.91	99.79	0.48	0.6	0.1	1.6	0.2	0.5	0.1	1.1	0.2	0.004	0.001	0.012	0.003	93.7	76.6	99.9	3.6
7	4/4/2022	10:25 AM	10:40 AM				High Pressure	45	10	53	4 to 6	MOV_2341.mp4	99.54	99.92	97.53	99.96	0.20	0.5	0.2	1.1	0.1	0.6	0.3	1.1	0.2	0.007	0.002	0.015	0.002	81.8	31.1	99.9	10.9
8	4/4/2022	11:06 AM	11:21 AM				High Pressure	42	11	50	6 to 8	MOV_2342.mp4	99.03	99.61	97.79	99.95	0.36	0.4	0.2	0.8	0.1	1.8	0.7	2.6	0.4	0.028	0.012	0.041	0.006	93.6	68.8	100.0	4.1
9	4/4/2022	11:23 AM	11:38 AM				Low Pressure	53	11	50	6 to 8	MOV_2344.mp4	99.36	99.86	98.34	99.84	0.24	0.4	0.1	1.5	0.2	0.9	0.3	1.6	0.2	0.011	0.004	0.022	0.004	91.0	69.9	100.0	5.4
10	4/4/2022	12:11 PM	12:26 PM				Low Pressure	44	14	39	12 to 14	MOV_2348.mp4	98.90	99.52	97.21	99.74	0.40	0.6	0.3	1.4	0.2	0.7	0.3	1.4	0.2	0.010	0.004	0.020	0.003	93.4	36.5	100.0	4.6
11	4/4/2022	12:44 PM	1:00 PM				HP/LP Assisted	49	14	38	14 to 16	MOV_2351.mp4	97.66	98.47	85.49	99.57	1.81	0.2	0.1	3.4	0.2	5.5	2.6	56.4	3.2	0.088	0.030	0.315	0.017	97.4	0.1	100.0	3.4
12	4/4/2022	1:15 PM	1:31 PM				High Pressure South	49	14	38	14 to 16	MOV_2354.mp4	98.59	99.23	84.95	99.99	1.29	1.5	0.4	3.2	0.5	3.4	0.6	11.7	1.9	0.092	0.012	0.242	0.063	92.5	21.1	100.0	5.7
13	4/4/2022	1:33 PM	1:48 PM				Low Pressure South	52	14	38	14 to 16	MOV_2356.mp4	99.46	99.89	98.42	99.96	0.24	0.7	0.3	1.3	0.1	0.1	0.1	0.3	0.0	0.001	0.001	0.002	0.000	92.1	30.6	100.0	4.5
14	4/4/2022	1:56 PM	2:11 PM				High Pressure North	38	14	38	14 to 16	MOV_2358.mp4	98.88	99.50	97.34	99.73	0.45	0.1	0.0	0.1	0.0	0.3	0.1	0.7	0.1	0.003	0.001	0.008	0.001	92.6	72.7	100.0	4.1
15	4/4/2022	2:12 PM	2:27 PM				Low Pressure North	32	14	38	14 to 16	MOV_2359.mp4	99.49	99.85	97.81	99.99	0.38	0.3	0.2	0.8	0.1	0.1	0.1	0.2	0.0	0.001	0.001	0.002	0.000	89.4	16.3	100.0	6.1
16	4/4/2022	2:41 PM	2:57 PM				High Pressure	37	18	32	10 to 12	MOV_2362.mp4	98.04	98.79	96.29	99.39	0.51	0.4	0.2	0.9	0.1	1.2	0.6	2.3	0.3	0.020	0.008	0.041	0.006	89.9	64.2	99.9	5.7
17	4/4/2022	2:57 PM	3:12 PM				Low Pressure	45	18	32	10 to 12	MOV_2363.mp4	98.59	99.26	96.80	99.70	0.46	0.7	0.2	2.2	0.4	0.1	0.1	0.3	0.0	0.001	0.000	0.003	0.001	94.5	77.3	100.0	3.2
18	4/4/2022	3:32 PM	3:47 PM				High Pressure	34	19	32	12 to 14	MOV_2365.mp4	98.90	99.51	96.36	99.85	0.46	0.6	0.4	1.0	0.1	0.2	0.1	0.3	0.0	0.002	0.001	0.002	0.000	95.2	84.9	99.9	2.3
19	4/4/2022	3:48 PM	4:07 PM				Low Pressure	38	19	32	12 to 14	MOV_2366.mp4	98.46	99.15	96.42	99.56	0.52	0.1	0.1	0.2	0.0	0.5	0.2	1.1	0.2	0.007	0.002	0.016	0.003	93.3	60.4	99.9	4.5
20	4/4/2022	4:22 PM	4:37 PM				High Pressure	37	19	30	8 to 10	MOV_2367.mp4	98.68	99.34	96.70	99.74	0.52	0.2	0.1	0.6	0.0	3.2	2.3	4.2	0.3	0.056	0.037	0.076	0.007	96.7	86.3	100.0	1.9
21	4/4/2022	4:38 PM	4:53 PM				Low Pressure	45	19	30	8 to 10	MOV_2368.mp4	99.46	99.87	98.40	99.94	0.28	0.7	0.3	1.6	0.3	0.2	0.1	0.5	0.1	0.002	0.000	0.006	0.002	94.9	84.1	100.0	2.4
22	4/5/2022	8:07 AM	8:22 AM				Dual HP/LP	44	6	55	8 to 10	MOV_2369.mp4	99.57	99.91	96.62	99.99	0.32	0.4	0.2	3.7	0.3	0.9	0.2	17.8	2.7	0.025	0.002	0.881	0.118	87.8	0.1	99.3	6.0
23	4/5/2022	9:04 AM	9:19 AM				Low Pressure	68	6	55	12 to 14	MOV_2371.mp4	99.48	99.92	98.59	99.87	0.17	0.1	0.1	0.2	0.0	1.3	0.8	1.8	0.2	0.020	0.013	0.025	0.002	95.9	55.8	100.0	3.2
24	4/5/2022	9:35 AM	9:50 AM				Dual HP/LP	43	7	49	14 to 16	MOV_2374.mp4	98.83	99.45	96.35	99.88	0.52	0.6	0.3	1.3	0.2	0.2	0.1	0.5	0.1	0.001	0.001	0.005	0.001	90.8	0.1	99.9	6.6
25	4/5/2022	10:02 AM	10:17 AM				Dual HP/LP	48	8	42	8 to 10	MOV_2375.mp4	99.24	99.77	97.85	99.88	0.33	1.0	0.4	2.0	0.3	0.3	0.2	0.6	0.1	0.002	0.001	0.005	0.001	91.5	62.5	99.7	4.7
26	4/5/2022	10:46 AM	11:01 AM				Low Pressure	46	7	44	14 to 16	MOV_2380.mp4	98.80	99.36	94.26	99.99	0.97	0.2	0.1	1.2	0.1	0.4	0.1	1.1	0.2	0.004	0.000	0.014	0.002	77.4	27.7	100.0	12.2
27	4/5/2022	11:19 AM	11:40 AM				Dual HP/LP	42	7	42	18 to 20	MOV_2385.mp4	88.30	90.52	79.42	99.65	3.24	0.3	0.1	1.1	0.2	5.8	3.0	9.8	1.3	0.100	0.040	0.241	0.039	95.2	76.8	99.9	3.1
28	4/5/2022	11:55 AM	12:12 PM				Dual HP/LP	42	8	43	18 to 20	MOV_2390.mp4	93.40	94.85	78.99	99.99	3.78	0.1	0.0	0.9	0.1	1.7	0.1	4.6	1.2	0.021	0.000	0.063	0.017	82.9	0.1	99.9	19.1
29	4/5/2022	12:26 PM	12:41 PM				Low Pressure	46	8	44	18 to 20	MOV_2392.mp4	99.66	99.94	98.64	99.99	0.16	0.2	0.1	0.5	0.0	0.8	0.4	1.2	0.2	0.009	0.003	0.015	0.002	91.1	62.7	100.0	5.8
30	4/5/2022	12:53 PM	1:08 PM				Dual HP/LP	37	10	41	16 to 18	MOV_2396.mp4	98.43	99.11	87.37	99.87	1.02	0.4	0.1	1.0	0.1	0.5	0.2	1.5	0.2	0.005	0.002	0.016	0.002	85.6	3.8	99.9	10.6
31	4/5/2022	1:26 PM	1:41 PM				Low Pressure	43	10	41	22 to 24	MOV_2397.mp4	99.38	99.87	98.10	99.84	0.26	1.5	0.4	3.5	0.5	6.3	2.6	11.7	1.3	0.130	0.042	0.259	0.033	93.0	2.1	99.9	5.6
32	4/5/2022	1:57 PM	2:12 PM				High Pressure	48	9	42	18 to 20	MOV_2398.mp4	99.67	99.95	99.03	99.96	0.12	0.3	0.2	1.1	0.1	1.0	0.6	1.4	0.1	0.013	0.007	0.021	0.002	89.8	68.7	99.9	4.6
33	4/5/2022	2:26 PM	2:42 PM				Dual HP/LP	43	8	48	18 to 20	MOV_2400.mp4	96.17	97.20	87.69	99.03	1.56	0.2	0.1	0.3	0.0	5.5	3.9	7.9	0.6	0.088	0.068	0.127	0.009	95.7	54.4	100.0	2.9
34	4/5/2022	3:16 PM	3:31 PM				Dual HP/LP	49	7	63	10 to 12	MOV_2401.mp4	99.88	99.95	99.19	99.99	0.08	0.2	0.1	0.5	0.0	12.4	9.8	14.6	0.8	0.257	0.180	0.321	0.026	97.2	59.5	100.0	1.8
35	4/5/2022	3:46 PM	4:01 PM				High Pressure	50	7	68	4 to 6	MOV_2402.mp4	99.31	99.80	96.65	99.94	0.36	0.6	0.2	1.8	0.2	0.7	0.3	1.4	0.2	0.009	0.003	0.019	0.003	85.9	27.1	99.8	9.8
36	4/5/2022	4:02 PM	4:17 PM				Low Pressure	40	7	68	4 to 6	MOV_2403.mp4	99.66	99.95	98.94	99.99	0.15	0.5	0.2	1.5	0.2	0.9	0.6	1.3	0.1	0.012	0.009	0.016	0.001	94.5	54.7	100.0	4.6
37	4/5/2022	4:31 PM	4:46 PM				High Pressure	32	9	61	8 to 10	MOV_2404.mp4	99.52	99.91	97.99	99.93	0.24	0.8	0.4	1.2	0.1	0.2	0.1	0.4	0.0	0.003	0.001	0.005	0.001	92.7	64.7	100.0	5.1
38	4/5/2022	4:47 PM	5:02 PM				Low Pressure	37	9	61	8 to 10	MOV_2405.mp4	99.40	99.89	98.85	99.75	0.16	0.5	0.3	1.0	0.1	0.6	0.4	0.9	0.1	0.007	0.004	0.011	0.001	96.2	82.6	100.0	2.1
39	4/5/2022	5:13 PM	5:28 PM				Dual HP/LP	55	7	68	6 to 8	MOV_2406.mp4	99.23	99.78	97.26	99.88	0.31	0.2	0.1	0.4	0.0	1.0	0.7	1.4	0.1	0.010	0.007	0.016	0.001	85.7	55.2	100.0	6.9
40	4/5/2022	5:40 PM	5:55 PM				High Pressure	52	6	67	8 to 10	MOV_2407.mp4	98.35	99.06	91.53	99.64	0.79	1.6	0.8	2.3	0.3	3.1	1.5	26.3	1.0	0.072	0.042	0.108	0.010	94.4	28.5	100.0	4.8
41	4/5/2022	5:55 PM	6:10 PM				Low Pressure	60	6	67	8 to 10	MOV_2408.mp4	99.56	99.88	93.28	99.99	0.46	0.3	0.2	1.4	0.2	0.5	0.1	1.2	0.3	0.005	0.000	0.012	0.003	89.4	36.5	99.8	6.9
42	4/6/2022	8:22 AM	8:37 AM				Dual HP/LP	68	2	79	10 to 12	MOV_2410.mp4	98.51	99.13	91.86	99.99	1.21	0.6	0.1	1.7	0.3	0.9	0.2	13.6	2.0	0.018	0.001	0.417	0.060	90.3	0.1	100.0	8.6
43	4/6/2022	8:51 AM	9:06 AM				High Pressure	37	1	78	12 to 14	MOV_2411.mp4	99.26	99.71	95.26	99.99	0.57	0.4	0.1	0.7	0.1	0.8	0.3	1.3	0.1	0.009	0.002	0.017	0.002	88.9	68.3	100.0	5.7
44	4/6/2022	9:08 AM	9:23 AM				Low Pressure	60	1	78	12 to 14	MOV_2412.mp4	97.88	98.66	95.20	99.05	0.56	0.1	0.1	0.7	0.0	1.1	0.8	1.9	0.1	0.011	0.007	0.017	0.001	94.7	59.2	100.0	4.7
45	4/6/2022	9:40 AM	9:55 AM				Low Pressure	48	3	75	10 to 12	MOV_2413.mp4	98.87	99.48	96.71	99.82	0.52	0.9	0.4	2.1	0.3	0.3	0.1	0.6	0.1	0.004	0.002	0.007	0.001	95.9	87.8	100.0	2.0
46	4/6/2022	10:46 AM	11:01 AM				Dual HP/LP	58	3	73	16 to 18	MOV_2416.mp4	98.66	99.31	95.78	99.92	0.61	0.5	0.2	1.2	0.1	9.0	6.5	21.7	2.1	0.181	0.126	0.523	0.056	97.7	91.7	100.0	1.3
47	4/6/2022	11:44 AM	12:03 PM				Dual HP/LP	46	9	57	16 to 18	MOV_2418.mp4	97.12	97.96	85.06	99.99	3.18	0.8	0.1	3.7	0.7	0.6	0.1	6.5	0.8	0.008	0.000	0.140	0.014	86.5	0.1	100.0	14.4
48	4/6/2022	12:17 PM	12:32 PM				Dual HP/LP	75	9	48	10 to 12	MOV_2419.mp4	97.37	98.22	91.73	99.68	1.23	0.2	0.1	0.8	0.1	7.2	0.2	25.4	6.0	0.134	0.001	0.669	0.143	89.1	25.4	99.9	11.9
49	4/6/2022	12:58 PM	1:13 PM				Dual HP/LP	37	11	49	18 to 20	MOV_2420.mp4	98.55	99.23	96.83	99.75	0.48	1.2	0.6	2.2	0.3	0.3	0.2	0.4	0.0	0.003	0.002	0.005	0.001	86.4	65.1	100.0	6.6
50	4/6/2022	2:14 PM	2:29 PM				High Pressure	40	7	43	12 to 14	MOV_2422.mp4	99.10	99.68	97.87	99.85	0.28	0.1	0.1	0.3	0.0	6.6	4.2	8.5	0.6	0.131	0.090	0.179	0.013	97.0	86.5	100.0	2.2
51	4/6/2022	3:27 PM	3:42 PM				Dual HP/LP	43	12	43	30 to 32	MOV_2423.mp4	99.18	99.74	97.84	99.81	0.31	2.0	1.2	3.3	0.3	0.1	0.1	0.5	0.0	0.001	0.001	0.003	0.000	96.2	6.4	100.0	7.0
52	4/6/2022	4:01 PM	4:16 PM				Low Pressure	50	8	29	26 to 28	MOV_2424.mp4	99.41	99.83	97.99	99.99	0.37	0.8	0.4	1.9	0.2	0.2	0.1	0.4	0.0	0.002	0.001	0.004	0.000	92.3	77.4	100.0	4.1
53	4/6/2022	4:17 PM	4:22 PM				High Pressure	36	8	29	26 to 28	MOV_2425.mp4	99.27	99.80	98.23	99.95	0.27	0.1	0.0	0.2	0.0	0.1	0.0	0.1	0.0	0.000	0.000	0.001	0.000	82.3	53.7	99.6	8.6
54	4/7/2022	7:33 AM	7:48 AM				Dual HP/LP	58	-1	68	10 to 12	MOV_2426.mp4	98.75	99.40	96.77	99.56	0.25	0.3	0.2	0.7	0.1	1.6	1.1	6.4	0.6	0.020	0.010	0.091	0.008	90.8	69.3	100.0	4.9
55	4/7/2022	8:05 AM	8:20 AM				Dual HP/LP	49	-1	67	18 to 20	MOV_2427.mp4	98.43	99.10	95.05	99.99	0.70	0.6	0.1	2.4	0.5	1.6	0.2	9.7	1.7	0.037	0.001	0.298	0.060	86.2	0.1	99.9	8.9
56	4/7/2022	8:32 AM	8:47 AM				Low Pressure	28	-2	72	14 to 16	MOV_2428.mp4	99.10	99.67	97.47	99.86	0.39	0.1	0.1	0.1	0.0	0.7	0.3	1.2	0.2	0.010	0.004	0.022	0.003	94.2	82.2	100.0	3.2
57	4/7/2022	8:59 AM	9:14 AM				Dual HP/LP	61	-1	79	18 to 20	MOV_2429.mp4	97.10	98.00	94.26	99.35	0.79	0.2	0.1	0.3	0.0	2.2	0.5	4.6	0.7	0.031	0.004	0.087	0.014	80.9	0.1	100.0	15.8
58	4/7/2022	9:24 AM	9:39 AM				Dual HP/LP	53	2	70	12 to 14	MOV_2430.mp4	99.13	99.63	95.71	99.99	0.54	0.4	0.1	1.0	0.1	1.3	0.8	1.8	0.2	0.018	0.008	0.029	0.003	85.9	61.0	99.9	6.8
59	4/7/2022	10:00 AM	10:15 AM				Low Pressure	40	5	54	20 to 22	MOV_2432.mp4	99.08	99.67	97.97	99.68	0.27	0.2	0.1	0.4	0.0	0.9	0.5	1.7	0.2	0.013	0.007	0.023	0.003	92.3	74.8	99.9	4.3
60	4/7/2022	10:30 AM	10:45 AM				Dual HP/LP	70	5	50	16 to 18	MOV_2433.mp4	96.31	97.31	70.17	99.87	3.27	0.4	0.1	2.3	0.3	6.5	0.1	24.5	7.5	0.118	0.000	0.643	0.149	74.6	0.1	99.7	22.1
61	4/7/2022	10:55 AM	11:10 AM				Dual HP/LP	42	3	51	18 to 20	MOV_2434.mp4	99.57	99.91	98.26	99.99	0.29	0.5	0.1	2.4	0.3	0.2	0.0	0.6	0.1	0.002	0.000	0.007	0.001	81.3	25.6	100.0	10.3
62	4/7/2022	11:24 AM	11:39 AM				Low Pressure North	37	5	45	18 to 20	MOV_2435.mp4	99.00	99.55	96.22	99.99	0.56	0.5	0.2	1.3	0.1	0.7	0.4	1.0	0.1	0.010	0.006	0.014	0.001	91.5	67.8	99.9	4.4
63	4/7/2022	11:41 AM	11:56 AM				Low Pressure South	43	5	45	18 to 20	MOV_2437.mp4	99.36	99.79	96.54	99.99	0.49	0.6	0.1	1.8	0.3	0.2	0.1	0.8	0.1	0.001	0.000	0.008	0.001	84.6	0.1	100.0	11.6
64	4/7/2022	11:58 AM	12:13 PM				High Pressure	41	5	45	18 to 20	MOV_2438.mp4	99.03	99.56	97.11	99.99	0.64	3.0	0.1	7.0	1.7	0.6	0.1	6.0	1.1	0.009	0.001	0.117	0.020	95.0	62.2	100.0	4.2
65	4/7/2022	12:33 PM	12:48 PM				High Pressure North	34	6	38	22 to 24	MOV_2439.mp4	99.68	99.94	98.36	99.99	0.23	0.3	0.2	0.6	0.1	0.9	0.5	1.5	0.2	0.014	0.004	0.031	0.005	90.6	49.5	100.0	5.0
66	4/7/2022	12:49 PM	1:04 PM				High Pressure South	48	6	38	22 to 24	MOV_2440.mp4	99.75	99.95	99.30	99.99	0.09	0.6	0.2	0.9	0.1	0.9	0.5	1.9	0.2	0.014	0.005	0.034	0.005	89.8	59.8	99.9	5.7
67	4/7/2022	1:08 PM	1:23 PM				Low Pressure	58	6	38	22 to 24	MOV_2441.mp4	99.19	99.71	97.04	99.91	0.46	0.2	0.1	0.5	0.1	0.2	0.1	0.8	0.1	0.002	0.001	0.010	0.002	84.2	35.5	99.9	8.3
68	4/7/2022	1:37 PM	1:52 PM				Low Pressure	31	6	41	20 to 22	MOV_2442.mp4	99.64	99.94	98.71	99.98	0.18	0.4	0.1	1.2	0.2	1.3	0.4	3.3	0.5	0.028	0.008	0.062	0.013	93.4	59.5	100.0	4.8
69	4/7/2022	2:21 PM	2:36 PM				High Pressure	32	9	34	10 to 12	MOV_2443.mp4	98.80	99.42	94.76	99.99	0.54	0.4	0.2	0.8	0.1	0.7	0.3	1.2	0.1	0.009	0.003	0.018	0.002	91.7	74.7	100.0	4.7
70	4/7/2022	2:37 PM	2:52 PM				Low Pressure	39	9	34	10 to 12	MOV_2444.mp4	99.27	99.80	92.67	99.96	0.41	0.3	0.1	1.1	0.1	0.6	0.2	1.0	0.1	0.008	0.002	0.014	0.002	87.8	31.9	100.0	7.6
71	4/7/2022	3:13 PM	3:28 PM				Low Pressure	37	7	37	16 to 18	MOV_2445.mp4	98.57	99.23	96.53	99.87	0.46	0.6	0.2	1.3	0.2	0.3	0.1	0.7	0.1	0.003	0.001	0.010	0.001	87.7	32.2	99.8	6.5
72	4/7/2022	3:49 PM	4:04 PM				Dual HP/LP	68	8	36	20 to 22	MOV_2446.mp4	98.48	99.14	92.52	99.99	0.90	0.3	0.1	1.5	0.2	7.0	0.2	41.4	8.5	0.137	0.001	0.663	0.185	87.9	18.3	99.9	10.2
73	4/7/2022	4:54 PM	5:09 PM				Dual HP/LP	58	11	32	6 to 8	MOV_2451.mp4	98.02	98.78	95.48	99.79	0.97	0.3	0.1	0.9	0.1	1.2	0.1	2.8	0.5	0.013	0.001	0.032	0.006	80.3	0.1	99.3	11.9
74	4/7/2022	5:26 PM	5:41 PM				Dual HP/LP	91	7	42	16 to 18	MOV_2452.mp4	98.73	99.34	81.51	99.95	1.90	1.2	0.4	3.1	0.6	22.6	9.1	148.3	7.9	0.842	0.334	1.423	0.204	96.8	47.8	100.0	2.9
75	4/8/2022	8:08 AM	8:23 AM				Low Pressure	39	-2	66	0 to 2	MOV_2453.mp4	98.29	99.01	96.13	99.42	0.49	1.0	0.6	1.4	0.1	0.7	0.5	0.9	0.1	0.012	0.010	0.015	0.001	95.8	85.8	100.0	1.9
76	4/8/2022	8:24 AM	8:39 AM				High Pressure	30	-2	66	0 to 2	MOV_2454.mp4	99.43	99.87	98.58	99.92	0.25	0.7	0.3	1.8	0.3	0.3	0.1	0.5	0.1	0.004	0.001	0.006	0.001	94.9	71.6	100.0	3.6
77	4/8/2022	9:17 AM	9:35 AM				Dual HP/LP	76	2	55	0 to 2	MOV_2455.mp4	96.73	97.58	62.85	99.99	7.52	0.6	0.1	4.1	0.9	30.0	4.1	189.5	47.2	0.288	0.034	2.630	0.327	94.1	11.0	100.0	9.7
78	4/8/2022	9:45 AM	10:01 AM				Dual HP/LP	83	3	59	0 to 2	MOV_2459.mp4	95.02	96.23	66.03	99.91	5.35	0.2	0.1	2.0	0.3	6.1	0.2	24.0	4.8	0.100	0.001	0.525	0.104	87.1	0.1	100.0	23.7
79	4/8/2022	10:16 AM	10:26 AM				Dual HP/LP	57	8	42	0 to 2	MOV_2460.mp4	99.74	99.95	99.24	99.99	0.15	1.1	0.8	2.0	0.2	0.2	0.1	0.4	0.0	0.001	0.001	0.002	0.000	95.3	6.8	100.0	7.6
80	4/8/2022	10:56 AM	11:11 AM				Dual HP/LP	112	10	29	0 to 2	MOV_2461.mp4	99.44	99.90	96.64	99.97	0.24	0.5	0.4	0.8	0.1	53.6	38.4	71.4	4.8	1.098	0.828	1.358	0.102	96.8	84.8	100.0	1.7
81	4/8/2022	11:26 AM	11:44 AM				Dual HP/LP	112	10	29	0 to 2	MOV_2462.mp4	99.36	99.82	94.10	99.95	0.42	0.5	0.2	2.2	0.1	61.2	23.2	171.8	7.0	1.239	0.291	1.633	0.149	96.5	0.1	100.0	4.1
82	4/8/2022	11:55 AM	12:10 PM				Dual HP/LP	167	12	25	6 to 8	MOV_2463.mp4	99.20	99.72	87.28	99.86	1.10	0.7	0.3	1.4	0.3	53.8	31.5	186.2	12.0	1.104	0.591	1.875	0.306	96.9	45.4	99.9	2.8
83	4/8/2022	12:26 PM	12:41 PM				Low Pressure	50	11	26	4 to 6	MOV_2464.mp4	96.50	97.49	91.54	99.40	1.30	0.1	0.1	0.2	0.0	1.6	0.8	2.6	0.3	0.025	0.013	0.039	0.006	88.8	68.3	99.9	5.1
84	4/8/2022	1:01 PM	1:16 PM				Low Pressure South	37	13	25	4 to 6	MOV_2466.mp4	99.60	99.91	98.56	99.99	0.26	0.3	0.0	1.0	0.2	0.6	0.2	1.1	0.2	0.008	0.002	0.017	0.003	95.1	75.2	99.9	3.1
85	4/8/2022	1:16 PM	1:31 PM				Low Pressure North	36	13	25	4 to 6	MOV_2467.mp4	99.18	99.69	94.35	99.92	0.64	0.5	0.1	1.2	0.2	0.4	0.1	1.2	0.3	0.005	0.001	0.017	0.004	93.7	69.5	100.0	4.2
86	4/8/2022	1:34 PM	1:49 PM				Low Pressure South	20	13	25	4 to 6	MOV_2468.mp4	99.52	99.91	98.47	99.96	0.22	0.2	0.1	0.4	0.0	0.1	0.1	0.2	0.0	0.001	0.001	0.002	0.000	94.9	66.2	99.9	3.1
87	4/8/2022	2:07 PM	2:22 PM				Low Pressure	59	14	23	4 to 6	MOV_2469.mp4	99.78	99.94	98.61	99.99	0.20	0.8	0.3	1.2	0.2	0.5	0.3	1.2	0.2	0.004	0.003	0.011	0.001	92.4	54.4	100.0	6.9
88	4/8/2022	2:23 PM	2:38 PM				Low Pressure	40	14	23	4 to 6	MOV_2470.mp4	99.70	99.95	98.88	99.94	0.12	0.9	0.5	1.2	0.1	0.4	0.3	0.5	0.0	0.003	0.002	0.005	0.000	96.5	14.6	100.0	3.2
89	4/8/2022	3:02 PM	3:17 PM				High Pressure	50	13	21	2 to 4	MOV_2471.mp4	99.21	99.69	88.08	99.99	0.85	1.0	0.4	2.4	0.5	9.4	5.7	26.2	1.7	0.265	0.142	0.406	0.044	94.9	58.3	99.9	4.0
90	4/8/2022	3:19 PM	3:34 PM				High Pressure	63	13	21	2 to 4	MOV_2472.mp4	99.21	99.76	98.03	99.94	0.28	0.2	0.1	0.9	0.1	1.1	0.4	4.6	0.5	0.009	0.004	0.023	0.003	90.4	51.1	100.0	6.4
91	4/8/2022	4:16 PM	4:31 PM				Dual HP/LP	42	15	18	2 to 4	MOV_2474.mp4	98.90	99.52	97.75	99.81	0.34	0.2	0.1	1.8	0.1	2.0	1.2	2.9	0.3	0.034	0.022	0.045	0.004	96.6	42.3	100.0	2.9
92	4/8/2022	4:49 PM	5:04 PM				Low Pressure	30	12	17	8 to 10	MOV_2475.mp4	99.14	99.72	97.70	99.69	0.26	0.6	0.3	1.2	0.1	0.4	0.2	0.6	0.1	0.004	0.002	0.007	0.001	87.2	66.9	99.9	6.1

Appendix B: Validation of the VISR method

The VISR method has been extensively tested using extractive sampling as a control method. The largest blind test was conducted by the Petroleum Environmental Research Forum (PERF), a non-profit organization created to provide a stimulus to and a forum for the collection, exchange, and analysis of research information relating to the petroleum industry. PERF project 2014-10 (Test) was created by participating PERF companies to provide a test platform for various developers/vendors of flare remote sensing technologies (Invitees) to participate in a blind test to evaluate the effectiveness of each technology. The test was administered by John Zink at their test facility in Tulsa, Oklahoma, USA. [redacted] sponsoring PERF companies and Providence Photonics was one of the vendors participating in the PERF test. The results of the PERF test have now been released to the public.

The PERF test consisted of 43 individual test points. Each test point was measured with an extractive system suspended over the flame, as shown in *Figure 15*. With the exception of 3 test points provided as calibration data (per test protocol), the test was completely blind for the participants. The flare performance (Combustion Efficiency), flow rate and fuel composition were not shared with the participants until after their individual results were submitted.

The VISR method performed quite well in the PERF test. *Figure 16* below shows the VISR results compared to the control method (extractive results) across the 43 test points. Overall, the VISR result was within 1% of the extractive result and the accuracy was even better for the higher CE range (above 95%).

Figure 15. VISR method demonstrated as part of the PERF remote flare monitoring blind testing.

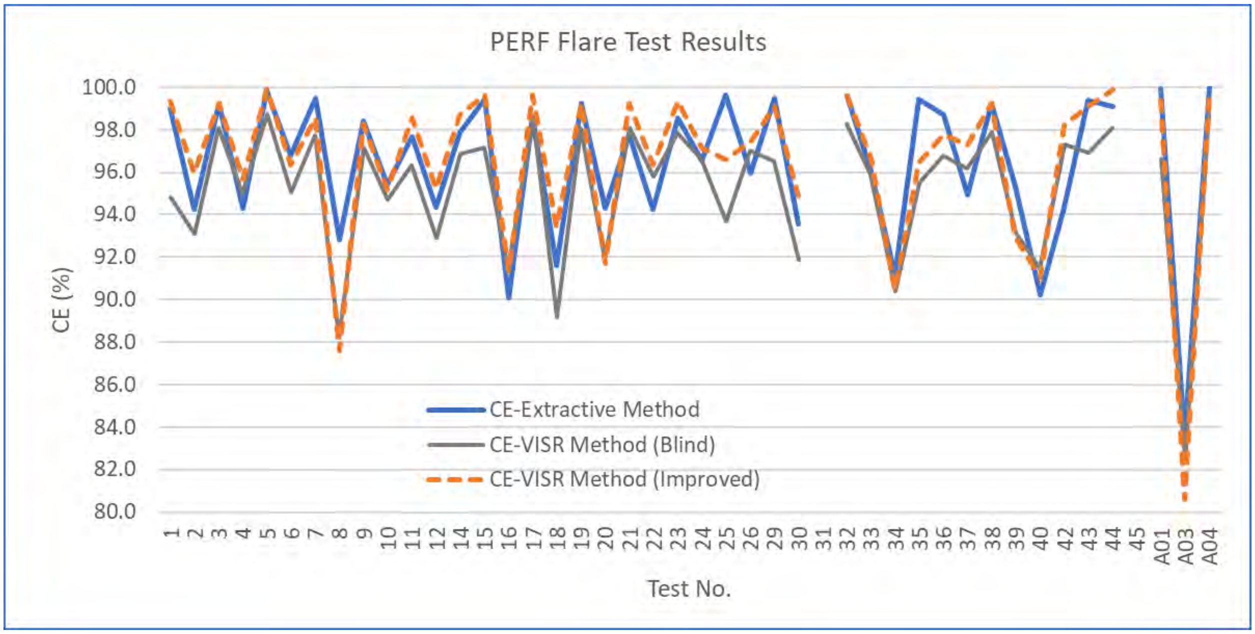

Figure 16. PERF test results, VISR (remote) vs. Extractive.

Note that the CE definition used by VISR was slightly different than what was used for the PERF extractive results. *Equation 1* below shows the calculation used to determine CE from the extractive results:

$$CE\ (\%) = \frac{CO_2(vol\%)}{CO_2(vol\%) + \frac{[CO(ppmvd) + 3\ \times THC(ppmvd)]}{10000}} \times 100$$

Equation 1

The VISR method uses the same equation but excludes the CO component. Extractive testing (including the PERF study) conducted by Providence Photonics, it was shown that the concentration of CO in the combustion plume (especially when CE is greater than 95%) is orders of magnitude lower than either CO2 or THC. Therefore, the effect of excluding CO from the CE equation is negligible.

Some definitions of CE also include soot (IE carbon) in the denominator, which means the presence of smoke will tend to lower CE. The VISR method does not measure carbon soot when determining CE, which is consistent with the definition of CE in a regulatory context.

A systematic negative bias of -0.8% was observed in the VISR results when compared to the extractive results from the PERF test. Providence Photonics has continued developing the CE algorithm since the PERF testing and believes that the systematic bias has been removed. This was confirmed by Providence Photonics by re-running the PERF data with the latest VISR algorithm. More information regarding the validation testing performed on the VISR method can be found in the PERF Report.

Another set of extractive testing was conducted at Zeeco's test facility in Tulsa, Oklahoma, USA and is discussed in a peer reviewed journal article[1].

Appendix C: Combustion Efficiency Versus Destruction Efficiency

With respect to emissions calculations or GHG reporting, it is important to consider the difference between combustion efficiency (CE) and destruction efficiency (DE). The VISR method measures CE, which is a measure of the efficiency of the flame to convert hydrocarbons into carbon dioxide and water. If the combustion efficiency is 100%, then all of the hydrocarbons have been oxidized all the way to carbon dioxide, leaving no hydrocarbons in the post combustion plume. CE will be reduced as the percentage of hydrocarbon in the post combustion plume increases. Destruction efficiency is a measure of the percentage of a compound that is destroyed (IE converted into another form), but not necessarily oxidized to the ultimate combustion product of carbon dioxide and water. In this case, it represents the percentage of hydrocarbons destroyed. The hydrocarbons could be converted to carbon dioxide, carbon monoxide, soot or another compound. As a result, DE is typically higher than CE. For emission inventory purposes, flares are generally deemed to have a DE of 98%, meaning 98% of the hydrocarbons sent to the flare are converted into another form. There is no quantitative method to convert the VISR CE data to DE, however we do have some points of reference. The US EPA Refinery Sector Rule (40 CFR 63.670 (r) equates a CE of 96.5% to a DE of 98%. The rule references the John Zink combustion handbook (Baukal, 2001).

In addition, there have been two major studies which have measured both CE and DE with extractive sampling: the 2010 TCEQ Study and the 2016 PERF Study. Both of these studies were conducted at John Zink's research facility in Tulsa, Oklahoma. Taken collectively, these studies provide 71 individual measurements of CE and DE. *Figure 8* below shows the relationship between CE and DE from these two studies.

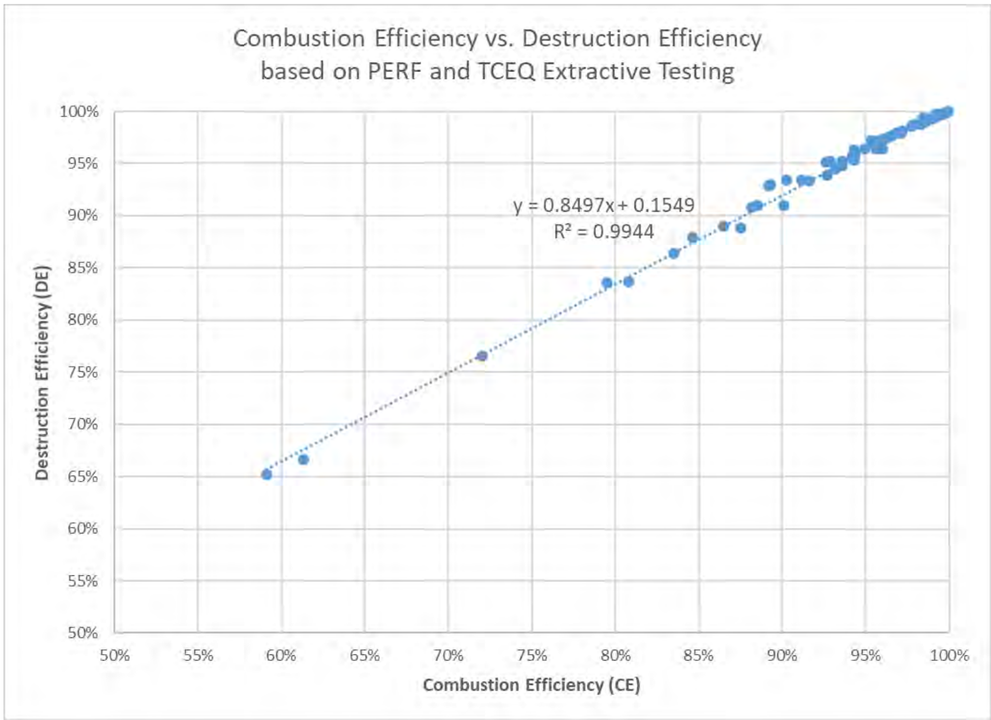

Figure 17. CE vs DE from extractive sampling during PERF and VISR studies.

As demonstrated by the chart, the relationship between DE and CE is quite linear. The fit equation to this data has an R^2 of 0.99. Equation 2 below can be used to convert CE to DE using this correlation:

$$DE\ (\%) = CE\ (\%) * 0.8497 + 0.1549$$

Equation 2

It should be noted that when SI is high and CE appears to be low, the destruction efficiency (DE) may still be high as the hydrocarbons are combusted into soot instead of oxidizing to the ultimate combustion products of water and CO_2. The CE-DE relationship shown in *Figure 8* is established under no smoke conditions. There has not been sufficient study on a similar CE-DE relationship when there is significant smoke in the flare. This equation will be valid for CE within a range of 60% to 99.4%. Above 99.4%, the DE will be capped at 100%. Below 60%, there is no extractive data available to extend the correlation.

PROVIDENCE PHOTONICS

Mantis Performance Report for [redacted] Flare Test

July 2022

Prepared for

[redacted]

PROVIDENCE PHOTONICS PROJECT NO. [redacted]

PREPARED BY
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Introduction

[redacted]) retained Providence Photonics, LLC (Providence) to conduct performance measurements with the Mantis flare monitor. The test was funded in part by the DOE ARPA-E REMEDY program to improve the DRE of flares and reduce methane emissions from flares. The objective of the test was to provide a baseline for [redacted] DreamDuo flare.

The flare test was conducted at the [redacted] [redacted] [redacted] on July 26th, 2022. This report summarizes the performance results recorded by the Mantis flare monitor.

Background

The Mantis utilizes a multi-spectral midwave infrared imager to measure relative concentrations of combustion gases. The method was designed to be a continuous and autonomous remote flare monitor and can be integrated in the plant control system. In this instance, the Mantis data was recorded locally and retrieved later for reporting purposes.

Results

The results from Mantis measurements are tabulated in **Appendix A** and a summary is provided in *Table 1 below*.

Date	Start Time (Local)	End Time (Local)	Test Description	Distance (m)	Temp (°C)	RH (%)	CE Avg (%)	DRE Avg (%)	SI Avg	FF Avg (m2)	FH Avg (MMBTU/HR)	FS Avg (%)
7/26/2022	10:49 AM	10:53 AM	Test Point 2	145	31	45	98.63	99.30	0.7	197.5	6.77	95.9
7/26/2022	11:04 AM	11:07 AM	Test Point 3	145	31	45	98.90	99.51	0.5	170.2	5.21	96.6
7/26/2022	11:16 AM	11:22 AM	Test Point 4	145	31	45	99.05	99.65	0.5	134.2	3.38	96.2
7/26/2022	11:58 AM	12:02 PM	Test Point 4c	145	31	45	99.09	99.69	0.4	94.8	2.05	96.5
7/26/2022	12:55 PM	1:00 PM	Test Point 5	145	32	39	99.14	99.73	0.5	53.6	1.00	97.1
7/26/2022	1:02 PM	1:07 PM	Test Point 6	145	32	39	99.29	99.85	0.5	31.0	0.54	97.2
7/26/2022	1:09 PM	1:15 PM	Test Point 7	145	32	39	99.13	99.72	0.5	26.9	0.44	97.0
7/26/2022	1:17 PM	1:24 PM	Test Point 8	145	32	39	99.20	99.76	0.4	17.6	0.28	97.1
7/26/2022	1:26 PM	1:32 PM	Test Point 9	145	32	39	99.41	99.91	0.3	13.7	0.19	97.1
7/26/2022	1:39 PM	1:45 PM	Test Point 10	145	32	39	99.49	99.94	0.3	10.7	0.14	97.1
7/26/2022	1:48 PM	1:54 PM	Test Point 4d	145	32	39	99.16	99.74	0.4	87.2	1.91	96.5
7/26/2022	2:10 PM	2:15 PM	Test Point 12a	145	32	39	99.54	99.91	0.6	21.7	0.39	94.4
7/26/2022	2:17 PM	2:20 PM	Test Point 12b	145	32	39	99.66	99.93	0.7	21.6	0.43	95.2
7/26/2022	2:26 PM	2:29 PM	Test Point 12b Repeat	145	33	36	99.58	99.96	0.6	21.7	0.44	96.0
7/26/2022	2:36 PM	2:38 PM	Test Point 13	145	33	36	99.51	99.90	1.2	22.4	0.47	95.4
7/26/2022	2:40 PM	2:43 PM	Test Point 14	145	33	36	99.04	99.57	2.6	21.7	0.50	95.2
7/26/2022	2:55 PM	2:59 PM	Test Point 15	145	33	36	99.60	99.94	0.5	22.9	0.40	94.9
7/26/2022	3:01 PM	3:04 PM	Test Point 16	145	33	36	97.61	98.39	0.5	25.0	0.40	91.3
7/26/2022	3:08 PM	3:14 PM	Test Point 17	145	33	36	99.48	99.84	0.4	14.4	0.22	94.8
7/26/2022	3:18 PM	3:22 PM	Test Point 18	145	35	30	98.95	99.55	0.4	9.2	0.13	94.7
7/26/2022	3:29 PM	3:35 PM	Test Point 19	145	35	30	99.12	99.60	2.3	12.7	0.24	94.6
7/26/2022	3:38 PM	3:42 PM	Test Point 20	145	35	30	99.01	99.48	2.9	18.5	0.39	94.7
7/26/2022	3:43 PM	3:48 PM	Test Point 21	145	35	30	98.60	99.16	5.1	16.2	0.38	94.5
7/26/2022	3:56 PM	4:00 PM	Test Point 22	145	35	30	99.45	99.91	0.6	28.7	0.57	95.4

Table 1: Summary Mantis Results.

Flare Performance Metrics

VISR provides five flare performance metrics at a 1-second data interval:

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 2 indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the VISR imager. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the VISR imager in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this test the flame size was above the minimum number of pixels for all measurements performed.

The second important DQI is the Smoke Index level. As the smoke index increases above 2.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Extractive testing shows that SI values above 3.0 may cause a small negative bias on the CE measurement (< 1%) and SI values above 5 may cause a significant negative bias to CE, as confirmed by testing with an extractive sampling method as a control. Any data points with a smoke index above 3 were removed from the summary tables and **Appendix A** results.

Summary

A flare test was conducted at the [redacted] [redacted] [redacted] on July 26th, 2022. The test was funded in part by the DOE ARPA-E REMEDY program to improve the DRE of flares and reduce methane emissions from flares. The objective of the test was to provide a baseline for [redacted] DreamDuo flare. Raw 1-second data and summary data are provided along with this report.

References

1. Yousheng Zeng, Jon Morris & Mark Dombrowski (2015) Validation of a new method for measuring and continuously monitoring the efficiency of industrial flares, Journal of the Air & Waste Management Association, 66:1, 76-86, DOI: 10.1080/10962247.2015.1114045
2. Yousheng Zeng, Jon Morris. (2019, April 2nd). *Precision and Accuracy of the VISR Method for Flare Monitoring*. Air Quality Measurement Methods and Technology, Durham, North Carolina, United States.

Appendix A: Results

Date/Time					Conditions			Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (CST)	End Time (CST)	Test Description	Distance (m)	Temp (°C)	RH (%)	CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	7/26/2022	10:49 AM	10:53 AM	Test Point 2	145	31	45	98.63	99.30	95.46	99.62	0.55	0.7	0.2	2.2	0.3	197.5	9.3	274.3	31.6	6.77	0.11	8.46	1.17	95.9	70.0	100.0	3.4
2	7/26/2022	11:04 AM	11:07 AM	Test Point 3	145	31	45	98.90	99.51	93.16	99.82	0.71	0.5	0.1	1.1	0.2	170.2	107.5	209.1	25.4	5.21	2.85	7.02	1.17	96.6	90.8	100.0	1.9
3	7/26/2022	11:16 AM	11:22 AM	Test Point 4	145	31	45	99.05	99.65	95.68	99.72	0.48	0.5	0.1	3.5	0.3	134.2	22.8	324.5	30.5	3.38	0.28	5.08	0.96	96.2	24.1	100.0	4.7
4	7/26/2022	11:58 AM	12:02 PM	Test Point 4c	145	31	45	99.09	99.69	95.57	99.95	0.30	0.4	0.1	1.4	0.2	94.8	60.4	181.6	16.7	2.05	1.33	3.20	0.43	96.5	68.3	99.8	2.8
5	7/26/2022	12:55 PM	1:00 PM	Test Point 5	145	32	39	99.14	99.73	98.36	99.60	0.15	0.5	0.1	1.6	0.2	53.6	39.4	119.2	6.8	1.00	0.74	1.21	0.09	97.1	56.2	100.0	3.2
6	7/26/2022	1:02 PM	1:07 PM	Test Point 6	145	32	39	99.29	99.85	98.36	99.73	0.19	0.5	0.1	0.9	0.1	31.0	21.2	39.0	3.4	0.54	0.38	0.67	0.05	97.2	91.0	100.0	1.5
7	7/26/2022	1:09 PM	1:15 PM	Test Point 7	145	32	39	99.13	99.72	98.13	99.86	0.30	0.5	0.1	1.4	0.1	26.9	18.0	33.1	3.0	0.44	0.34	0.55	0.04	97.0	79.4	99.8	1.9
8	7/26/2022	1:17 PM	1:24 PM	Test Point 8	145	32	39	99.20	99.76	97.13	99.71	0.33	0.4	0.1	1.1	0.1	17.6	11.5	24.2	2.8	0.28	0.19	0.39	0.04	97.1	67.4	100.0	2.4
9	7/26/2022	1:26 PM	1:32 PM	Test Point 9	145	32	39	99.41	99.91	98.66	99.83	0.21	0.3	0.2	0.6	0.1	13.7	8.8	17.0	1.5	0.19	0.13	0.24	0.02	97.1	92.6	100.0	1.4
10	7/26/2022	1:39 PM	1:45 PM	Test Point 10	145	32	39	99.49	99.94	97.83	99.75	0.29	0.3	0.2	0.5	0.1	10.7	7.9	12.7	1.0	0.14	0.11	0.17	0.01	97.1	92.7	99.9	1.4
11	7/26/2022	1:48 PM	1:54 PM	Test Point 4d	145	32	39	99.16	99.74	98.36	99.83	0.16	0.4	0.2	2.0	0.2	87.2	18.5	155.6	11.5	1.91	0.19	2.31	0.25	96.5	65.0	100.0	2.8
12	7/26/2022	2:10 PM	2:15 PM	Test Point 12a	145	32	39	99.54	99.91	96.69	99.99	0.43	0.6	0.1	1.5	0.2	21.7	5.2	84.1	6.9	0.39	0.06	0.60	0.11	94.4	12.4	99.9	6.9
13	7/26/2022	2:17 PM	2:20 PM	Test Point 12b	145	32	39	99.66	99.93	96.88	99.99	0.43	0.7	0.2	1.8	0.3	21.6	5.2	32.3	6.1	0.43	0.05	0.63	0.15	95.2	50.6	99.9	4.5
14	7/26/2022	2:26 PM	2:29 PM	Test Point 12b Repeat	145	33	36	99.58	99.96	98.86	99.99	0.25	0.6	0.1	1.4	0.2	21.7	17.6	26.0	1.5	0.44	0.33	0.54	0.04	96.0	89.9	100.0	2.0
15	7/26/2022	2:36 PM	2:38 PM	Test Point 13	145	33	36	99.51	99.90	98.46	99.99	0.34	1.2	0.6	2.5	0.4	22.4	17.8	101.6	6.8	0.47	0.36	0.63	0.05	95.4	43.9	99.8	4.8
16	7/26/2022	2:40 PM	2:43 PM	Test Point 14	145	33	36	99.04	99.57	97.13	99.99	0.67	2.6	0.8	4.4	0.8	21.7	13.0	92.9	8.0	0.50	0.34	0.77	0.08	95.2	6.3	99.9	7.0
17	7/26/2022	2:55 PM	2:59 PM	Test Point 15	145	33	36	99.60	99.94	97.54	99.99	0.36	0.5	0.1	1.1	0.2	22.9	17.4	29.2	2.0	0.40	0.32	0.51	0.03	94.9	84.0	99.8	2.6
18	7/26/2022	3:01 PM	3:04 PM	Test Point 16	145	33	36	97.61	98.39	87.41	99.92	2.67	0.5	0.2	1.3	0.1	25.0	4.2	32.4	3.5	0.40	0.01	0.51	0.07	91.3	21.9	99.8	9.4
19	7/26/2022	3:08 PM	3:14 PM	Test Point 17	145	33	36	99.48	99.84	93.56	99.99	0.76	0.4	0.2	0.9	0.1	14.4	7.6	19.4	1.8	0.22	0.10	0.32	0.03	94.8	14.6	100.0	6.7
20	7/26/2022	3:18 PM	3:22 PM	Test Point 18	145	35	30	98.95	99.55	96.33	99.72	0.66	0.4	0.1	0.8	0.1	9.2	6.3	12.1	1.1	0.13	0.09	0.19	0.02	94.7	83.5	99.8	2.7
21	7/26/2022	3:29 PM	3:35 PM	Test Point 19	145	35	30	99.12	99.60	97.37	99.99	0.64	2.3	0.6	4.1	0.7	12.7	8.9	92.8	4.2	0.24	0.14	0.36	0.03	94.6	6.8	99.9	5.6
22	7/26/2022	3:38 PM	3:42 PM	Test Point 20	145	35	30	99.01	99.48	97.16	99.99	0.87	2.9	0.9	6.4	1.1	18.5	12.3	318.5	20.1	0.39	0.28	0.95	0.07	94.7	0.1	99.8	7.4
23	7/26/2022	3:43 PM	3:48 PM	Test Point 21	145	35	30	98.60	99.16	97.53	99.98	1.80	5.1	0.8	7.6	1.8	16.2	6.6	92.8	6.1	0.38	0.13	0.71	0.13	94.5	0.1	99.9	6.2
24	7/26/2022	3:56 PM	4:00 PM	Test Point 22	145	35	30	99.45	99.91	98.42	99.99	0.27	0.6	0.2	1.7	0.2	28.7	19.4	115.5	9.2	0.57	0.37	0.86	0.08	95.4	17.1	100.0	8.3

ANNEX E: Supply Chain Study Results Letter, Submitted September 19, 2023

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

API American Petroleum Institute

AXPC AMERICAN EXPLORATION & PRODUCTION COUNCIL

INGAA Interstate Natural Gas Association of America

IPAA INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

GPA MIDSTREAM ASSOCIATION

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

From June through September of 2023, the American Petroleum Institute (API), American Exploration and Production Council (AXPC), Interstate Natural Gas Association of America (INGAA), Independent Petroleum Association of America (IPAA), and GPA Midstream Association (the “Industry Trades”) conducted an operator survey of supply chain delays for components and equipment necessary to comply with the Environmental Protection Agency’s (EPA) proposed rule “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.” To comply with antitrust guidelines the survey was blinded, and data was gathered and complied by a third party consultant, John Beath Environmental.

The EPA’s OOOOb New Source Performance Standard (the “methane rule”) is a complex rule that will apply to many thousands of facilities in producing basins across the country. Because of the wide variety of conditions faced by these facilities, the challenges in acquiring equipment due to ongoing COVID-induced supply chain delays, and additional proposed rules which will apply to these sources such as EPA’s revisions to Subpart W of the Greenhouse Gas Reporting Program (GHGRP) that will also require equipment, **operators need a reasonable timeline based on a December 6, 2022 applicability date to come into compliance with the final methane rule.**

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

Responses to the survey included information from 11 basins; a majority of responses included information from the Permian Basin. The responses suggest that operators have the greatest supply chain concerns with pneumatics, control devices, storage vessels, associated gas, and fugitive emissions components.

The survey found that current backorder times for components range from 6+ to 24+ months. Implementation of the proposed methane rule is expected to increase current backorder times by an additional 6+ months. A November 15, 2021 applicability date is expected to substantially exacerbate the challenges of equipment acquisition over a December 6, 2022 applicability date.

The survey results indicate that reasonable compliance timelines, based on a December 6, 2022 applicability date, would need to allow a minimum of 12 to 26 months for operators to come into compliance with the final methane rule, as appropriate given supply chain backlogs for each affected facility.

Current and Anticipated Supply Chain Delays

- Current backorder is generally up to 12 months across affected facilities with additional lead time needed for specialized equipment.
- Finalization of NSPS OOOOb is expected to add a minimum of 6 months of additional backorder time across affected facilities.

Affected Facility	Current Procurement Lead Time ("Backorder") is Delayed	Anticipated Backorder upon NSPS OOOOb Finalization Compared to Existing Lead Time
Pneumatic Controllers and Pumps	• Up to 12 months across equipment options. • Electrical transformers and instrument air skids are experiencing variable delays with 24+ months indicated.	• Add 6 to 12 months
Control Device Provisions	• Up to 12 months for both control devices and other equipment (monitoring, etc.)	• Add 6 to 12 months for control devices and • Add 6+ months for other equipment.
Storage Vessels	• Up to 12 months for steel tanks, vent header control valves • Up to 24 months for VRUs and • Up to 30 months for PVRVs & thief hatches.	• Add 6+ months across equipment
Associated Gas	• Up to 18 months for VRUs, gas compressor skids	• Add 6 to 12 months
Fugitive Emissions Components	• Up to 12 months across monitoring options.	• Add up to 6 months
Other (miscellaneous equipment)	• Up to 18 months for VFDs	• Add 6 to 12 months for VFDs

Recommended OOOOb Compliance Timelines by Affected Facility

Affected Facility / Category	EPA Proposed Compliance Timeline	Anticipated Supply Chain Delay Upon Finalization *(Current lead time + additional anticipated lead time)*	Industry Trades Recommended Compliance Timeline
Pneumatic Controllers & Pumps	60 days	18 - 36 months	26 months
Control Devices and Closed Vent Systems	60 days	18-24 months	20 months
Associated Gas	60 days	30 months	24 months
Fugitive Emissions Components	60 days	18 months	12 months
Storage Vessels	30 - 60 days	18 - 36 months	26 months

API's February 13 comment letter[1] included anecdotal reports of members' supply chain constraints. This survey quantitatively expands on the supply chain issues raised to demonstrate the need for reasonable compliance timelines.

These recommended compliance timelines account only for supply chain delays and do not contemplate the additional time needed to install equipment. The recommendations reflect the realities of the supply chain, balanced with the urgency of aggressive industry action to achieve compliance with OOOOb and reduce emissions.

While this survey evaluated supply chain delays relative to OOOOb compliance and did not contemplate compliance with OOOOc, given the scope of the proposed rules and available data, similar supply chain constraints are anticipated to continue beyond the OOOOc implementation timeframe.

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[1] *https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428*

Equipment & Services Included by Affected Facility

☐ Survey responses included equipment and services for various compliance options for each affected facility (listed below).
☐ The survey included estimated equipment counts, supplier market, and supply chain delays.

Pneumatic Controllers & Pumps

- Electrical Transformers
- Solar Equipment
- Generator Skids
- Instrument Air Skids
- Electrical Valves/Controllers
- Replacement Pumps
- Replacement Controllers
- ECAT System
- Nitrogen Gas

Control Devices & Closed Vent Systems

- Flares
- Enclosed Combustion Devices
- Flow Meters
- Backpressure Valves
- Calorimeters
- Third-party Testing: Performance, Net Heating Value (NHV), Opacity
- Automatic Pilot Light
- Thermocouples
- Piping for Closed Vent System

Storage Vessels

- Steel Tanks
- Pressure-Vacuum Relief Valves (PVRVs) & Thief Hatches
- Vent Header Control Valve
- Vapor Recovery Units (VRUs)*

Associated Gas

- VRUs*
- Methane Pyrolysis Skids
- Gas Compressor Skids
- Gas to Liquids Skids
- Liquefied Natural Gas Production Skids

Fugitive Emissions Components

- Optical Gas Imaging (OGI) Cameras
- OGI Camera Technicians
- Third-party OGI Monitoring
- Third-party Alternative Screening Technology Monitoring
- Continuous Monitoring Systems
- Replacement Piping Components
- Handheld Methane Detectors

Other (Miscellaneous Equipment)

- Variable Frequency Drives (VFDs)
- Cabling (Electric/Communications)
- Engineering Analysis (Associated Gas, Pneumatic Pumps, etc.)
- Eductor Skid (for compressors)

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*VRUs were considered separately for Storage Vessels and Associated Gas since size and design may differ.

Estimated Equipment Counts Needed for NSPS OOOOb Compliance

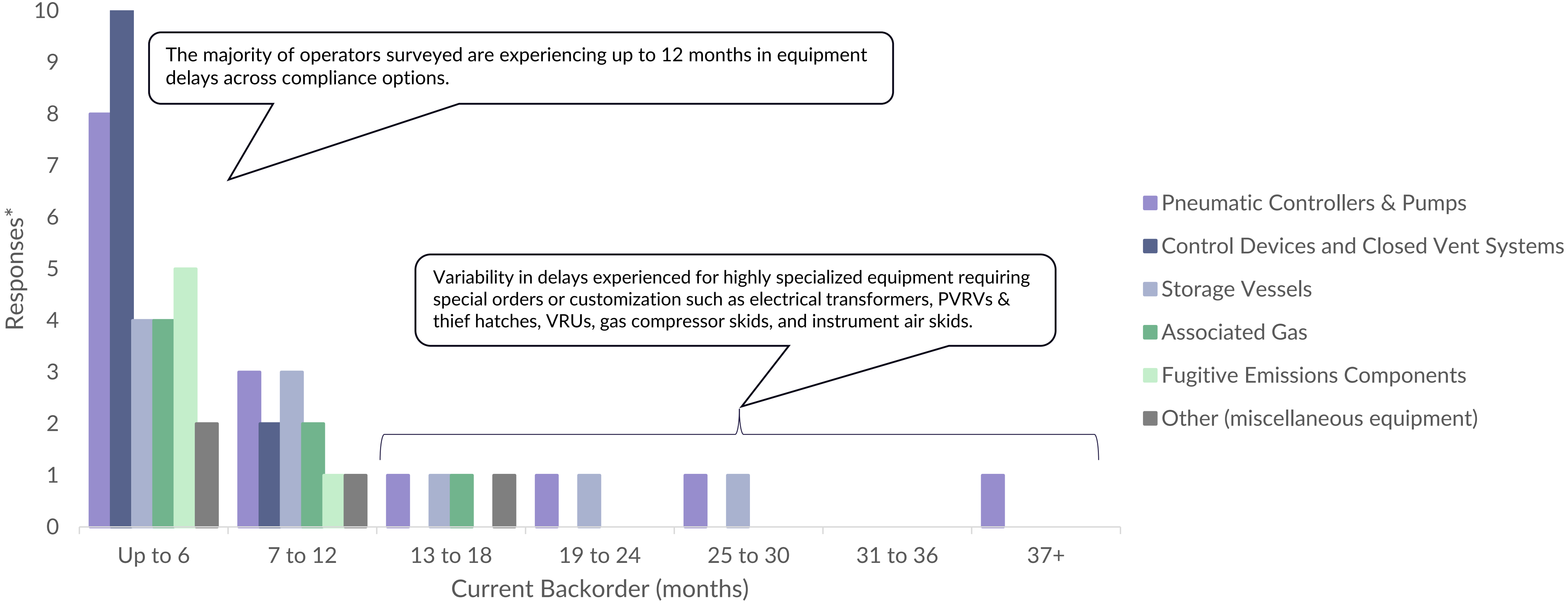
- **Pneumatic Controllers & Pumps**
  - Variety of responses highlight the need for multiple compliance options (i.e., no “one size fits all” solution).
  - 69% of responses indicated that instrument air skids would be needed.
  - Responses continue to indicate that a variety of power generation options will need to be used.
- **Control Devices & Closed Vent Systems**
  - 82% of responses indicated that flow meters would be needed.
  - 27% or more of responses indicated that third-party services (performance testing, NHV testing, or opacity monitoring) were being investigated for use.
- **Storage Vessels**
  - PVRVs & thief hatches were key equipment needed and were not considered in EPA’s cost analysis.
  - 29% of responses indicated that steel tanks would be needed, possibly as replacements for fiberglass tanks to facilitate a closed vent system. Replacement tanks were not considered in EPA’s cost analysis.
- **Associated Gas**
  - While operators support the concept of other types of beneficial use, responses indicated that operators were not planning to implement alternative technology options proposed by EPA (methane pyrolysis, gas to liquids, liquefied natural gas). The costs of alternative use options were not considered in EPA’s cost analysis.
- **Fugitive Emission Components**
  - Responses indicated that most operators were planning to implement their own OGI monitoring program (OGI cameras and technicians). A shortage of OGI technicians was also noted in the responses, and for gas processing operators, availability of qualified OGI camera technicians could be further limited based on the proposed certification and audit requirements in Appendix K. EPA’s cost analysis assumed that operators would use a third-party service.

Survey Results Compared to Previous API Comments

- Since the February 13, 2023 comment deadline, equipment backorder has generally remained the same or worsened.
- A reasonable compliance timeline of 12 to 26 months is needed based on a December 6, 2022 applicability date. Additional time would be needed if EPA maintains the November 15, 2021 applicability date.

Supply Chain Item	Survey Results (August 2023)	Previous API Comments (February 2023)	Summary of Comparison
Control Device Backorder	Up to 6 months: 75% 7 to 12 months: 25%	3 to 4 months	Backorder has increased by up to 8 months.
Flow Meter Backorder	Up to 6 months: 83% 7 to 12 months: 17%	6 to 8 months	Backorder remains approximately 6 to 8 months.
Flow Meter Installation Timeline (Hot Tap)	Up to 2 weeks: 50% 3 to 4 weeks: 33% 12+ weeks: 17%	Up to 4 months	Survey results may not reflect hot tap installations.
Instrument Air Skids Backorder	Up to 6 months: 58% 7 to 12 months: 25% 19+ months: 17%	8 to 12 months	Backorder has increased by up to 7 months.
Solar Panels Backorder	Up to 6 months: 80% 7 to 12 months: 20%	18 to 24 months	Backorder has decreased by 6 to 12 months.

Current Procurement Lead Time

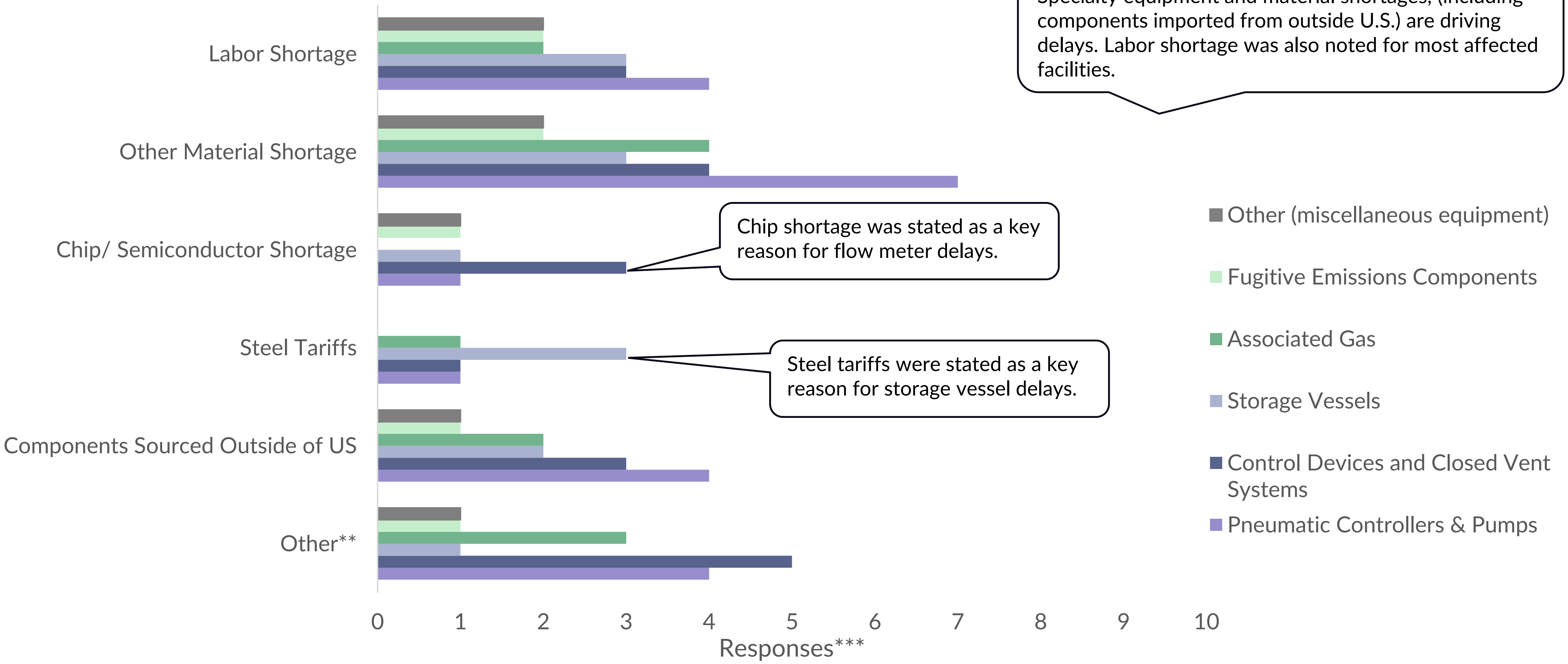


The majority of operators surveyed are experiencing up to 12 months in equipment delays across compliance options.

Variability in delays experienced for highly specialized equipment requiring special orders or customization such as electrical transformers, PVRVs & thief hatches, VRUs, gas compressor skids, and instrument air skids.

*Responses by affected facility based on maximum count for each backorder timeframe.

Supplier-Stated Reason(s) for Backorder*



Specialty equipment and material shortages, (including components imported from outside U.S.) are driving delays. Labor shortage was also noted for most affected facilities.

Chip shortage was stated as a key reason for flow meter delays.

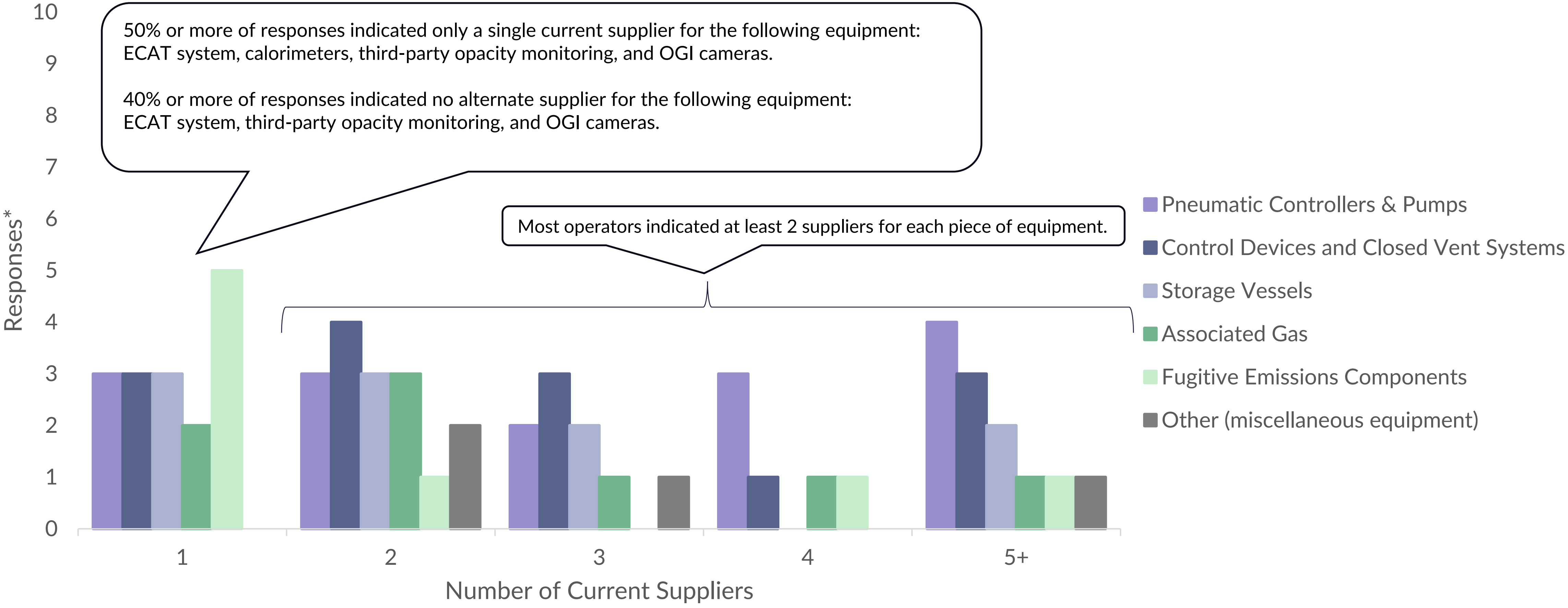
Steel tariffs were stated as a key reason for storage vessel delays.

* Responses could indicate more than one reason for backorder delays

** Other reasons vary by control option but include: “Fabricator backlog”; “Standard lead time”; “Limited inventory as order is customized”; “Engineering design required for proper equipment function”.

*** Responses based on maximum count for each reason.

Supplier Market



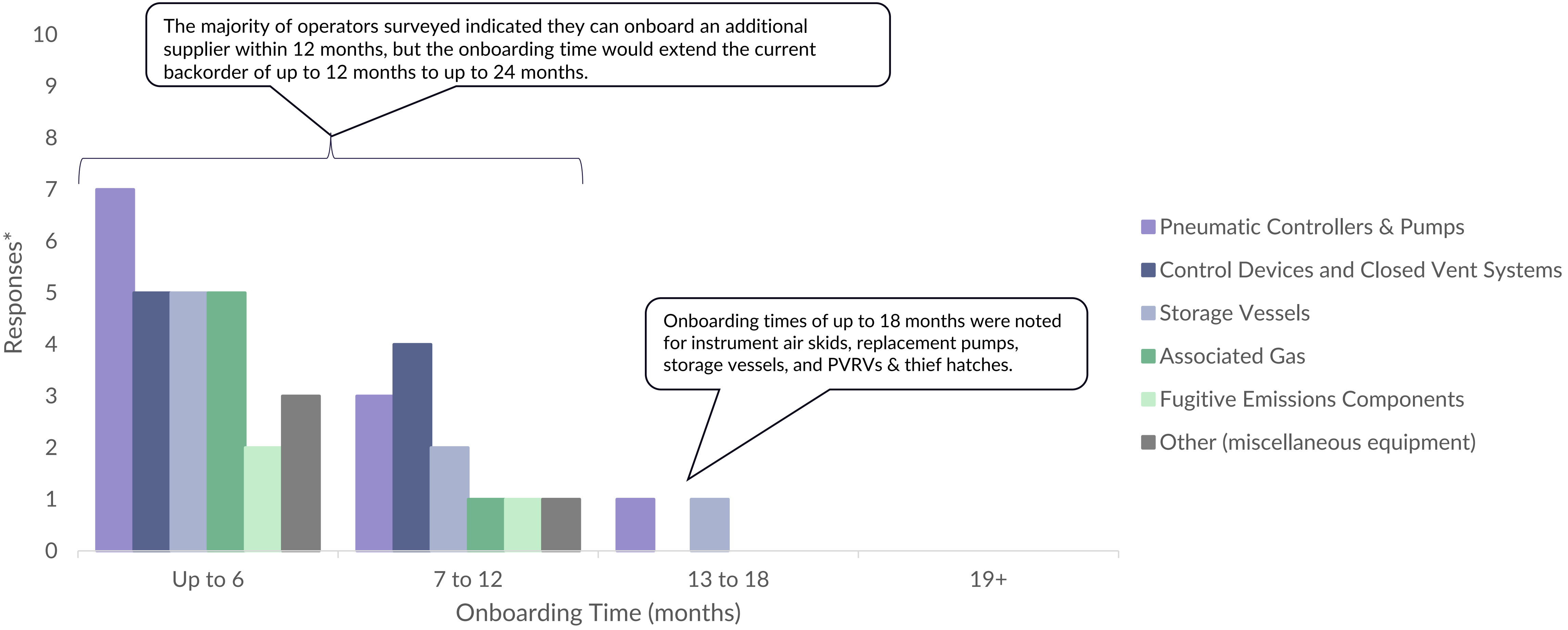
50% or more of responses indicated only a single current supplier for the following equipment: ECAT system, calorimeters, third-party opacity monitoring, and OGI cameras.

40% or more of responses indicated no alternate supplier for the following equipment: ECAT system, third-party opacity monitoring, and OGI cameras.

Most operators indicated at least 2 suppliers for each piece of equipment.

*Responses by affected facility based on maximum count for each number of current suppliers.

Onboarding Time for an Additional Supplier

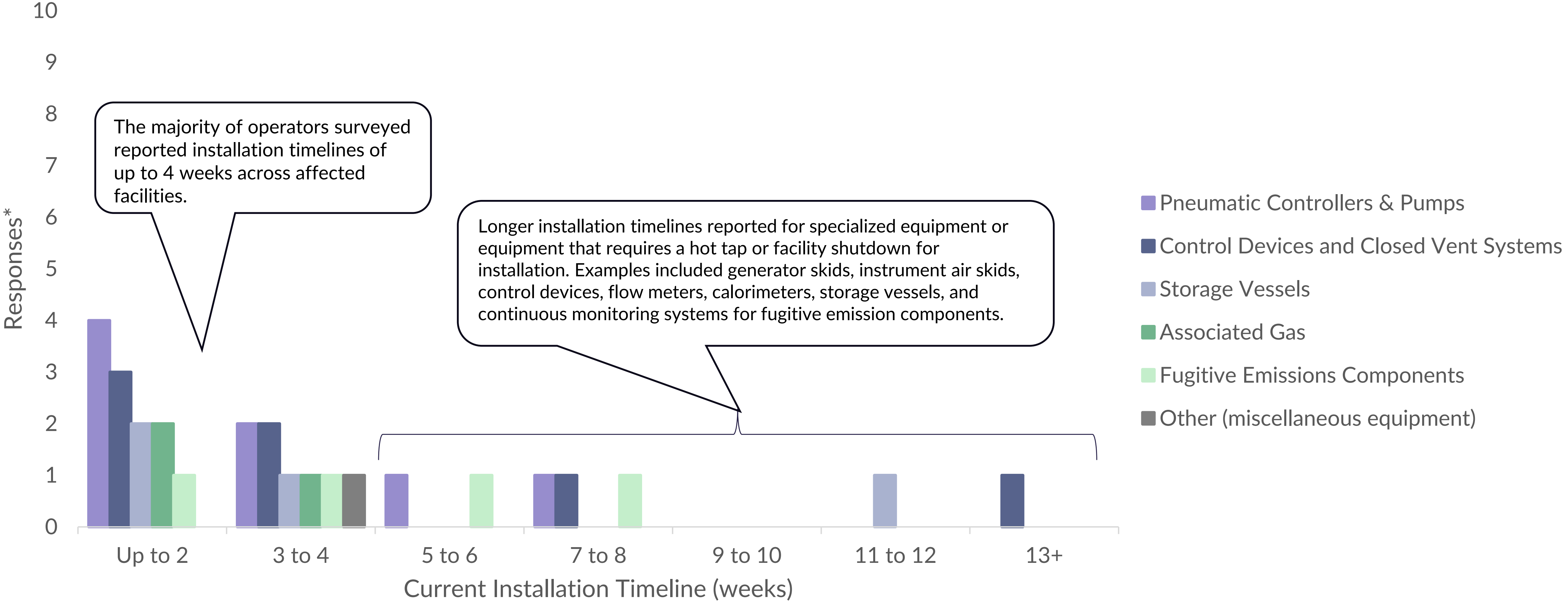


The majority of operators surveyed indicated they can onboard an additional supplier within 12 months, but the onboarding time would extend the current backorder of up to 12 months to up to 24 months.

Onboarding times of up to 18 months were noted for instrument air skids, replacement pumps, storage vessels, and PVRVs & thief hatches.

*Responses by affected facility based on maximum count for each onboarding timeframe.

Current Installation Timelines

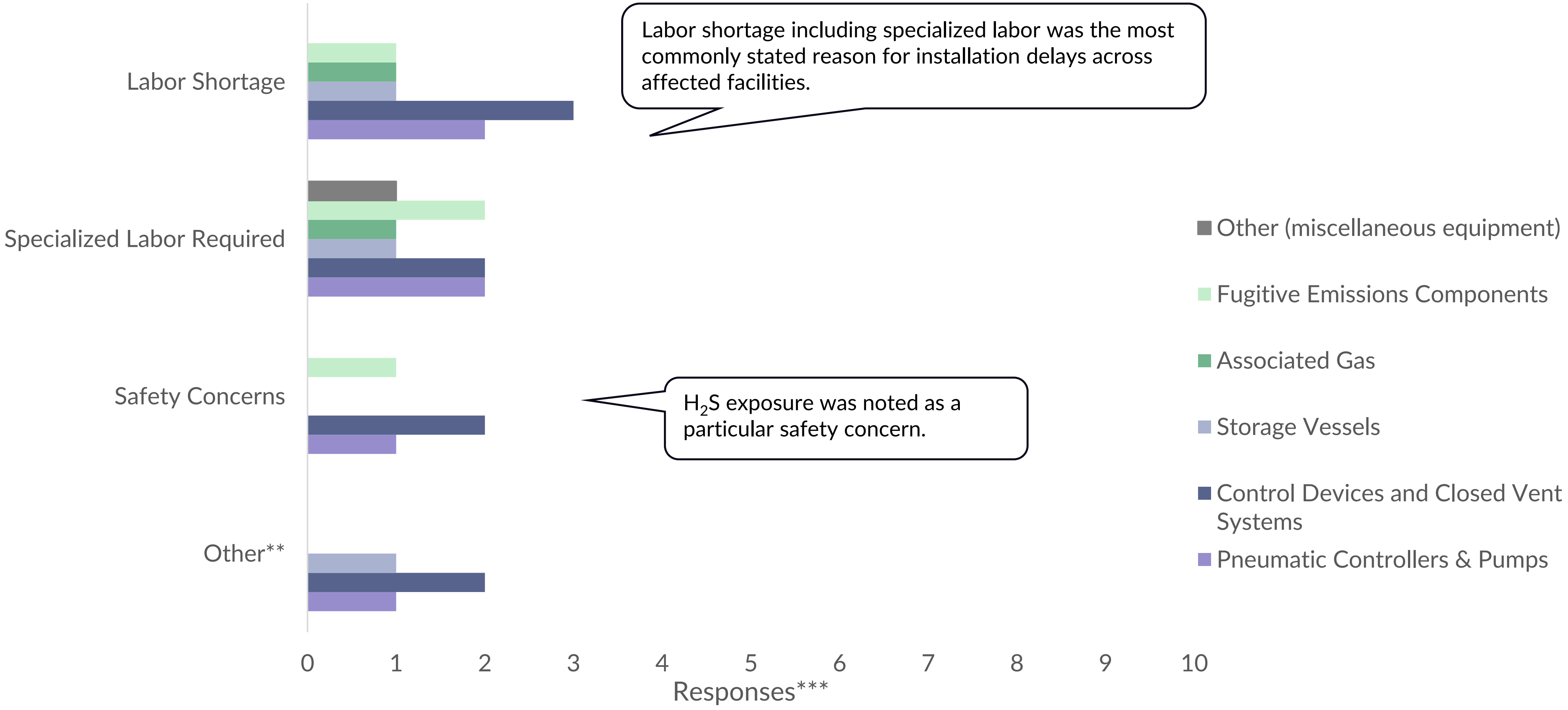


The majority of operators surveyed reported installation timelines of up to 4 weeks across affected facilities.

Longer installation timelines reported for specialized equipment or equipment that requires a hot tap or facility shutdown for installation. Examples included generator skids, instrument air skids, control devices, flow meters, calorimeters, storage vessels, and continuous monitoring systems for fugitive emission components.

*Responses by affected facility based on maximum count for each installation timeline.

Reason(s) for Installation Timelines



Labor shortage including specialized labor was the most commonly stated reason for installation delays across affected facilities.

H_2S exposure was noted as a particular safety concern.

* Responses could indicate more than one reason for backorder delays
** Other reasons vary by control option but include: “Engineering evaluation needed”; “Normal construction timeline”; “Weather, road conditions”.
*** Responses based on maximum count for each reason.

Docket ID No. EPA-HQ-OAR-2023-0234
October 2, 2023

ANNEX F: API Assessment of Properly Functioning and Malfunctioning Intermittent Bleed Pneumatic Controllers

Note: Data for this analysis is included separately within this docket in pdf format

ANNEX F

Analysis to Support Amendment to Calculation 3 for Intermittent Bleed Devices Monitoring

EPA should amend Equation W-1C to more accurately reflect available empirical data on emissions from properly functioning pneumatic controllers. This proposed amendment is consistent with data contained in Annex A, the API study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States," and data from the University of Texas,[1] both indicating that malfunctioning intermittent controllers are the primary source of measured emissions; the API pneumatic controller study data indicates it is approximately 85%.

Methods

The UT data[2,3] (304 controllers) and the API data (265 controllers) on natural gas driven intermittent bleed pneumatic controllers were reanalyzed to simulate the use of an IR camera to segregate equipment into malfunctioning and properly functioning controller categories and an average emission calculated for each category after segregation.

Controllers were separated into three groups based on time series behavior, where the detection threshold of the OGI camera was assumed to be 0.9 scfh (~17 g/hr). A sensitivity analysis was conducted to assess the impact of the assumed OGI detection threshold on the results.

Controller categories:[4]

- **Not Malfunctioning**:
    - **Low:** average value of the time series was less than the assumed detection threshold of the camera
    - **Proper:** Either
        - **Return to zero/baseline**: average value was at or above the detection threshold and the last value of the time series was below the threshold, or
        - **Baseline prior to actuation, but measurement terminated during actuation**: average value was at or above the detection threshold and at least half of the data points are less than the threshold.
- Otherwise **Malfunctioning**

The low category represents the equipment that would be viewed as "properly operating" irrespective of time series behavior because emissions would be undetected. The proper category represents equipment that would be viewed as having an actuation associated with emissions, but the actuation would terminate. The "not malfunctioning" category is the combined groups of low and proper. These should be indistinguishable through inspection, since OGI inspection results would be ambiguous as to whether a controller is emitting constantly below the detection limit of the camera or functioning

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[1] http://dept.ceer.utexas.edu/methane/study/datasets3.cfm Data downloaded September 2023.

[2] Ibid.

[3] All pneumatics in UT study were included as intermittent, though there were observations of both low and high continuous bleed devices intermingled. The result of this aggregation increases the properly operating emission factor through the inclusion of low-bleed continuous results that are below the assumed OGI detection threshold.

[4] Files attached dividing those time traces into low, proper, and malfunctioning categories for each the UT and the API data set provides visual inspection to assess implications of these criteria on the time series disaggregation.

properly. The malfunctioning category are the set of observations that are neither categorized as low nor proper. Both studies indicated that malfunctioning intermittent controllers were the majority of measured emissions, including ~85% in the API pneumatic controller study data.[5]

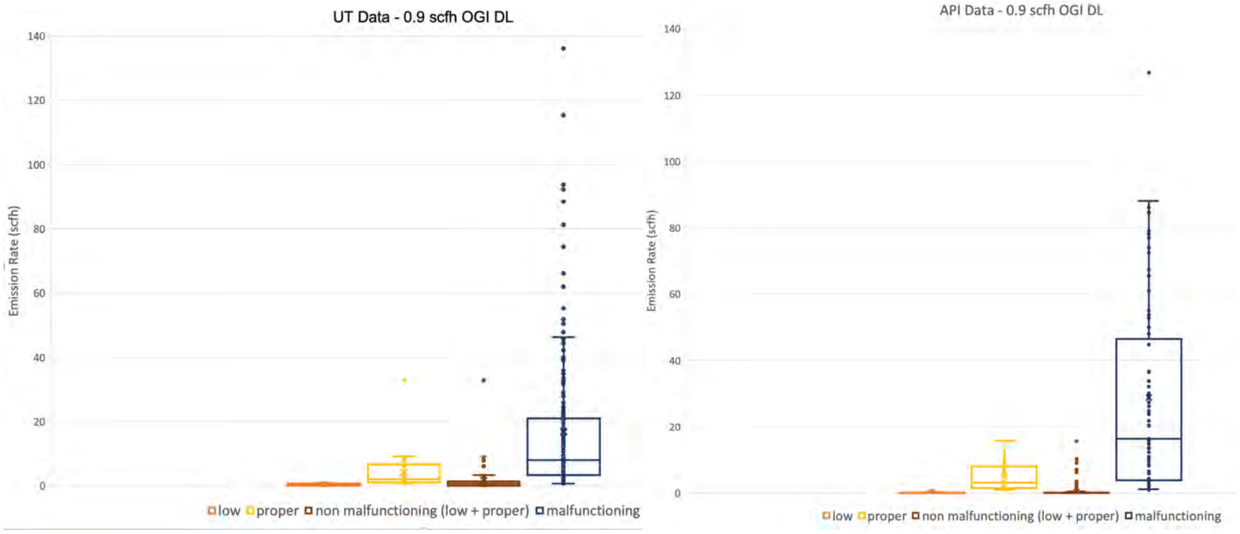
Results

The categorization with OGI camera assumed detection threshold of 0.9 scfh results in a revised set of properly functioning and malfunctioning emission factors of 0.9 and 20.0 scfh, respectively, which would result in a revised equation W-1C as below.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{20.0 \times T_{mal,z} + 0.9 \times (T_{t,z} - T_{mal,z})\} + (0.9 \times Count \times T_{avg})\right] \quad (Rev.Eq.W-1C)$$

The box and whisker plots in Figure 1 show the low, proper, non-malfunctioning, and the malfunctioning average measurements for the UT, API, and combined UT/API data and Table 1 provides the average and median values from each. As expected, each series is skewed.

Figure 1: Top Left – UT data; Top Right – API Data; Bottom – Combined UT + API data



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[5] API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States."

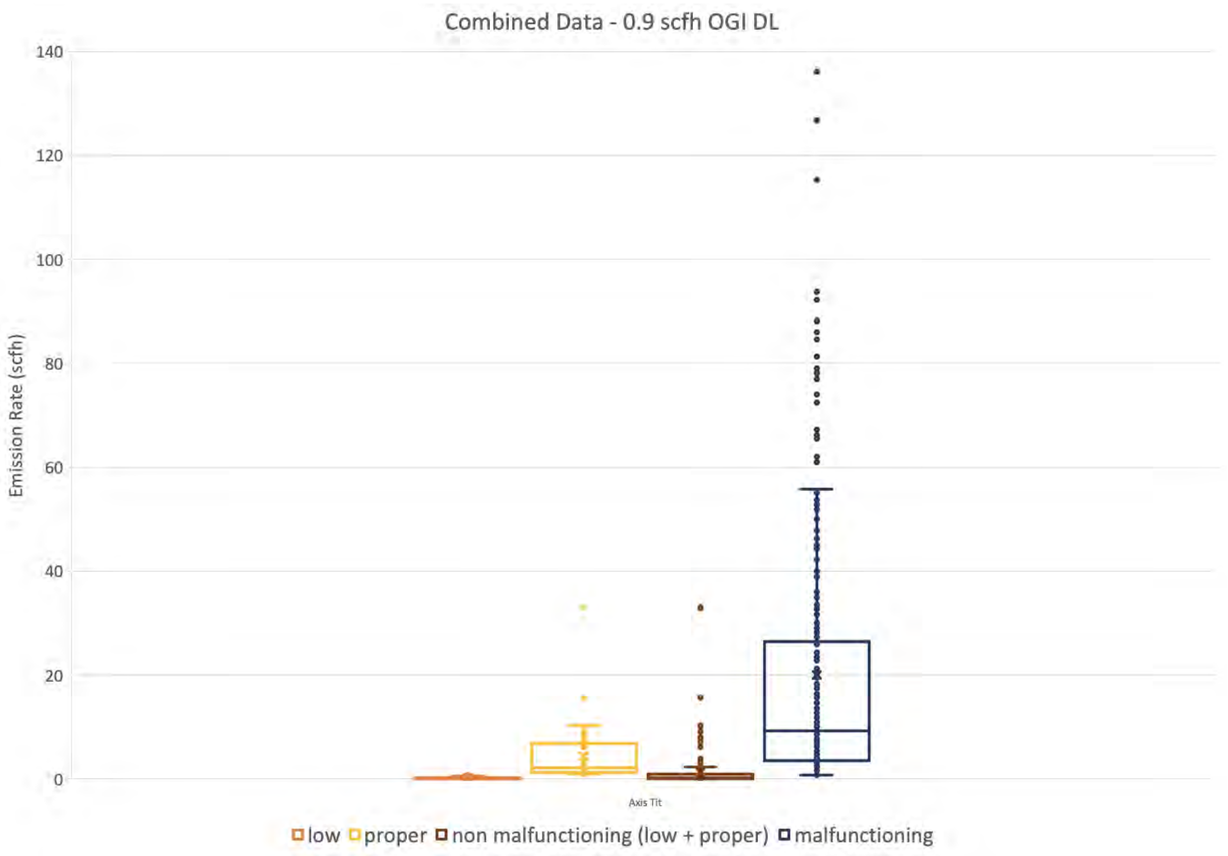

Table 1: Average and median emission rates (scfh) for the low, proper, non-malfunctioning and malfunctioning groups for each the UT, API and combined data sets along with equipment counts in each category.

	Low (scfh) [count]	Proper (scfh) [count]	Non-Malfunctioning (scfh) [count]	Malfunctioning (scfh) [count]
UT – Avg	0.3 [62]	4.3 [36]	1.8 [98]	16.5 [206]
API – Avg	0.1 [171]	5.0 [13]	0.5 [184]	28.8 [81]
Combined – Avg	0.2 [233]	4.4 [49]	**0.9 [282]**	**20.0 [287]**
UT – Median	0.3	2.0	0.7	8.0
API - Median	0.0	2.5	0.0	16.4
Combined - Median	0.0	2.2	0.0	9.3

The non-malfunctioning average emission rate in this segregation of equipment is 0.9 SCFH (68% lower than the proposed factor). The average emission rate of the designated malfunctioning equipment is 20.0 (24% higher than the proposed factor). This results in an overall emission per controller of 10.5 SCFH.

Overall, these results are quite consistent with those from the API pneumatic controller study, insofar as most of the emissions are attributable to the malfunctioning equipment. However, the method of segregating functioning from malfunctioning is different, resulting in a higher properly operating emission factor than the factor proposed in that study analysis shown in Table 2 below. The revised factor of 0.9 SCFH, though larger than the previously proposed factor from the API pneumatic controller study is still significantly lower than the proposed factor in the GHGRP Subpart W proposal.

Table 2: Comparison of the data analyses (former and this work) to proposed emission factors.

	API Study Report Average Emission Rate (SCFH)	API Reanalysis Average Emission Rate (SCFH)	Subpart W Proposed Factors (SCFH)	All data Reanalysis Average Emission Rate (SCFH)
Properly Functioning	0.28	0.5	2.82	**0.9**
Malfunctioning	24.1	28.8	16.1	**20.0**
Average of all equipment	9.25	9.1	-	10.5

One important limitation of the analysis on the UT data is that the time series are much shorter (~2 minutes in duration on average). However, the proposed rule requires an inspection period of 2 minutes.[6]

Sensitivity Analysis

A sensitivity analysis was performed to assess the impact of selecting a theoretical OGI detection limit of 0.6 SCFH. The results are shown in the figure below.

Figure 2: Data categorized as described in methods, with varying assumed detection threshold of OGI from 0.13 scfh to 10 scfh. Dashed lines show the variation of the malfunctioning pneumatic controller average (left axis), solid lines show the variation of the non-malfunctioning (properly operating) pneumatic controller average (left axis), and the dotted lines show the % of controllers that would be classified as malfunctioning under the different detection threshold scenarios (right axis). UT data are shown in orange, API data in blue, and the combined data are shown in black.

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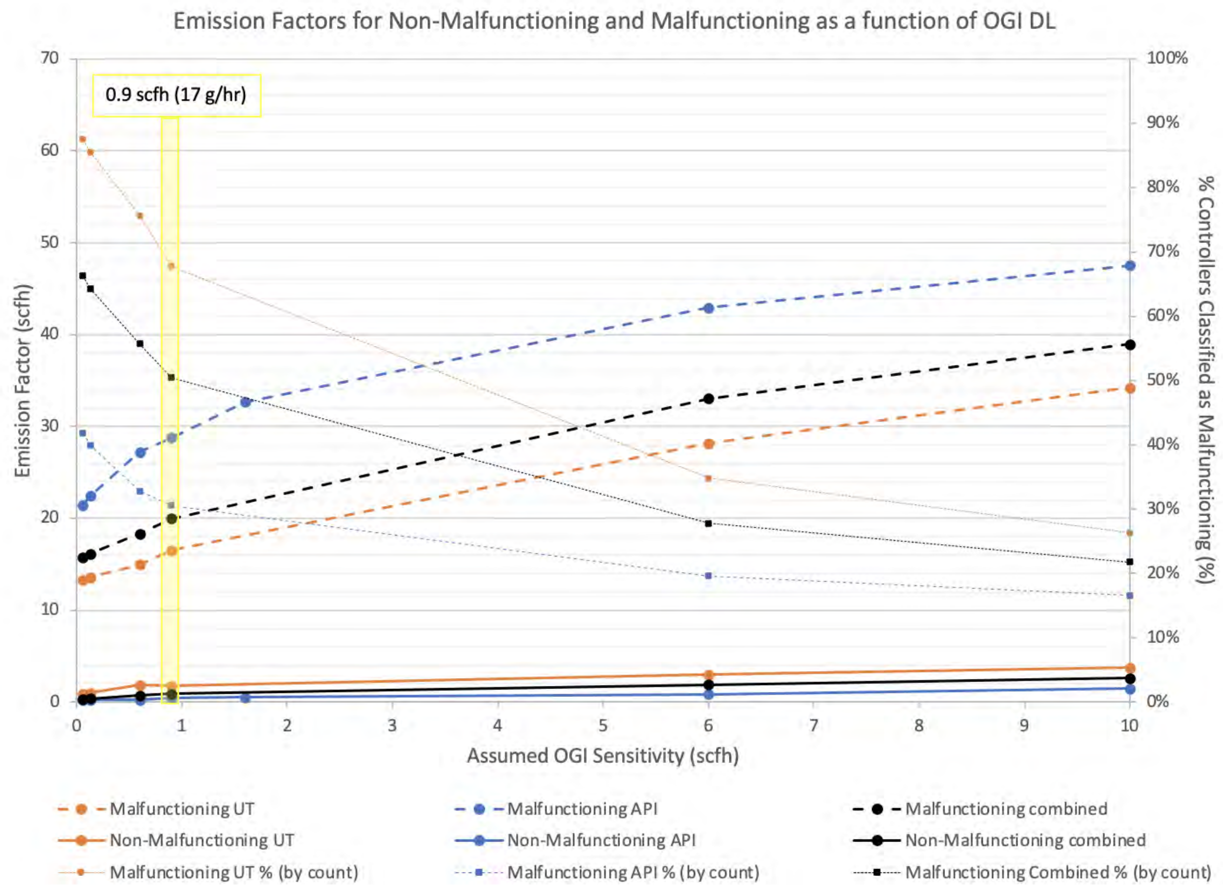
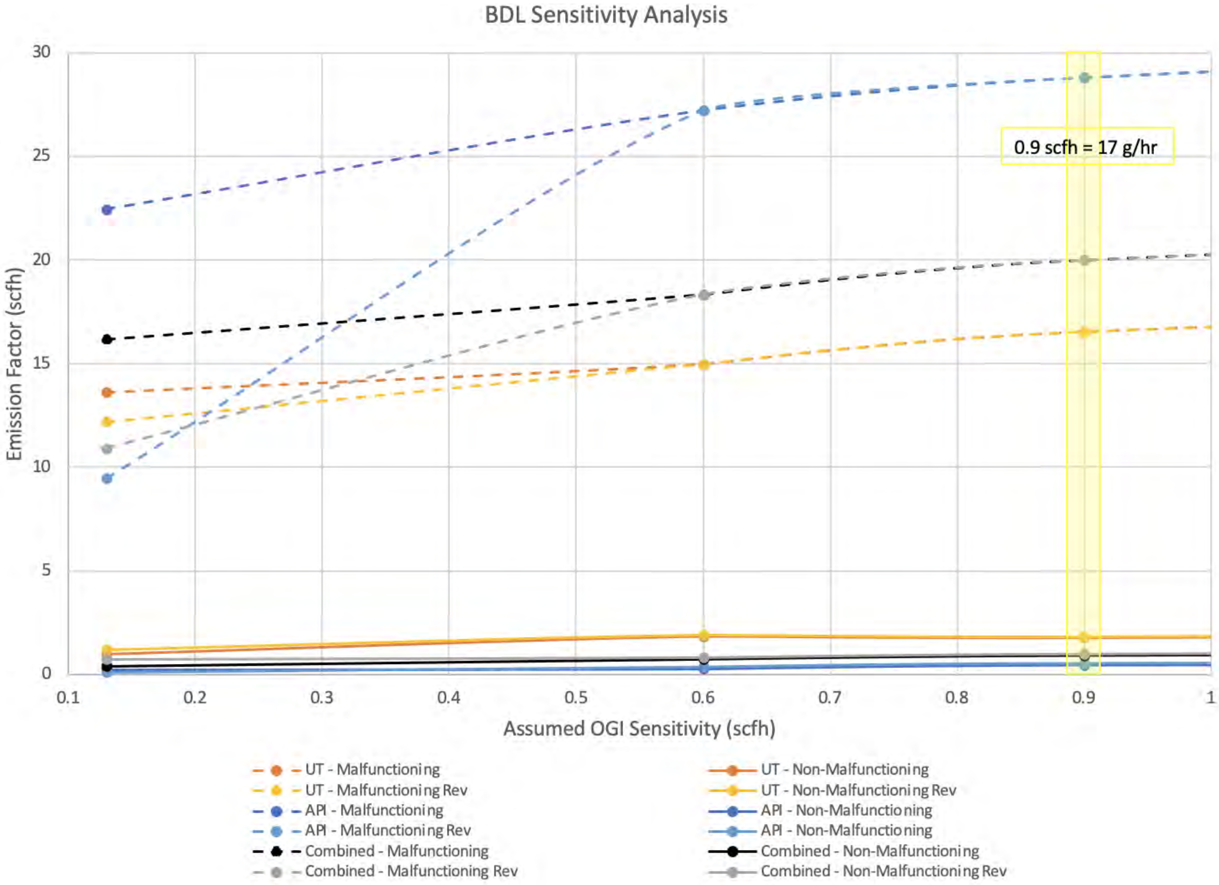
[6] "You must use one of the monitoring methods specified in § 98.234(a)(1) through (3) except that the monitoring dwell time for each device vent must be at least 2 minutes or until a malfunction is identified, whichever is shorter. A device is considered malfunctioning if any leak is observed when the device is not actuating or if a leak is observed for more than 5 seconds during a device actuation. If you cannot tell when a device is actuating, any observed leak from the device indicates a malfunctioning device."



The assumed detection threshold exceeds 10 scfh before the non-malfunctioning (properly operating) average emission reaches 2.82 scfh (proposed factor).

Similarly, a sensitivity analysis was performed to assess the impact of including instrument reported "zeroes" as zeroes. Data substitution was performed to replace all instances of zero with 0.13 scfh to represent the minimum detection limit of the high flowsampler employed in both studies. As shown in Figure 3, there are minor impacts to average emissions for detection thresholds for OGI below ~0.6 scfh, but there is no impact on the proposed range of emission factors.

Figure 3: Data categorized as described in methods, with varying assumed detection threshold of OGI from 0.13 scfh to 1 scfh under two scenarios: 1) data are used as reported and 2) zeroes are substituted with the instrument MDL of 0.13 scfh. Dashed lines show the variation of the malfunctioning pneumatic controller average (left axis) and solid lines show the variation of the non-malfunctioning (properly operating) pneumatic controller average (left axis). UT data are shown in dark orange with the revised data in light orange, API data in dark blue with the revised data in light blue, and the combined data are shown in black with the revised data shown in grey.


BDL Sensitivity Analysis
Emission Factor (scfh)
30
25
20
15
10
5
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Assumed OGI Sensitivity (scfh)
0.9 scfh = 17 g/hr
UT - Malfunctioning
UT - Malfunctioning Rev
API - Malfunctioning
API - Malfunctioning Rev
Combined - Malfunctioning
Combined - Malfunctioning Rev
UT - Non-Malfunctioning
UT - Non-Malfunctioning Rev
API - Non-Malfunctioning
API - Non-Malfunctioning
Combined - Non-Malfunctioning
Combined - Non-Malfunctioning Rev

AXPC
AMERICAN
EXPLORATION
& PRODUCTION
COUNCIL

March 26, 2024

U.S. Environmental Protection Agency
EPA Docket Center, Air and Radiation Docket
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

Subject: **Waste Emissions Charge for Petroleum and Natural Gas Systems**
Docket ID No. EPA–HQ–OAR–2023–0434

Dear Madam or Sir:

The American Exploration and Production Council (AXPC) appreciates the opportunity to provide input responsive to the Environmental Protection Agency's (EPA) Proposed Rule "Waste Emissions Charge for Petroleum and Natural Gas Systems" (89 FR 5318, January 26, 2024) ("WEC").

AXPC is a national trade association representing 34 leading independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate.

As part of this mission, AXPC members understand the importance of ensuring positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. The United States is a world leader in oil and natural gas production, achieving that status while at the same time substantially reducing emissions. The historic reductions in US greenhouse gas (GHG) emissions over the last decade have been driven by the emergence of US natural gas production as a low-cost source of reliable energy. It is important that regulatory policy enables us to build on that success.

AXPC companies are focused on reducing methane emissions from their operations and support effective and reasonable regulation of methane that balances the essential value of US oil and natural gas production with the global challenge of addressing climate change. AXPC companies believe collaboration amongst policy makers and industry partners is needed to find solutions that will meaningfully drive down emissions, while allowing US independent producers to meet the global demand for affordable and reliable oil and natural gas. It is in the spirit of this aim that we offer these comments to EPA proposed rule.

As established in the Inflation Reduction Act (IRA), the implementation of the WEC should be done in a manner that is equitable to operators of varying sizes and portfolios. AXPC is concerned that EPA's proposal offers a simplified calculation of methane intensity that does not take into account the products that the upstream *oil* and gas industry produces and in doing so unduly punishes operators who produce large amounts of energy in the form of oil or NGLs over other production profiles. In our detailed comments attached, we recommend that EPA amend the Facility Methane Intensity calculation to define the numerator as waste emissions relative to the amount of *natural gas sold*. In other words, defining WEC Facility Methane Emissions, as the portion of the emissions attributable to the natural gas sent to sales or facility throughput. Such an approach conforms to the plain reading of the statute and congressional intent; and it is consistent with life cycle assessment practices, and would help avoid unintended negative outcomes that might otherwise result from the inequitable program proposed.

Additionally, in order to stay true to Congress's directive, it is critical that EPA develop an approach to the Regulatory Compliance Exemption that ensures its availability and utility as Congress clearly intended. Under the terms of the proposal, the Regulatory Compliance Exemption would not be available for at least three years, and once available, will be virtually impossible to achieve. If EPA were to finalize such an approach, it would amount to giving no meaningful effect to Congress's intent to provide a Regulatory Compliance Exemption, standing in conflict with established legal precedent for such matters.

Finally, AXPC requests clarification from EPA on the netting provisions of "WEC applicable facilities." As explained further in AXPC's detailed comments, as currently proposed, the inability to net assets that have achieved regulatory compliance or whose emissions are below the WEC threshold may not incentivize deeper emission reductions. Similarly, inability to net assets at the parent company level may also hold back the incentives for operators to make the most impactful emission reductions in their portfolio of assets. We believe these outcomes to be contrary to both EPA and Congress's intent for this program.

With these priority topics in mind, we respectfully submit the below detailed comments on the (EPA's Proposed Rule to implement the "Waste Emissions Charge for Petroleum and Natural Gas Systems." We have identified a number of issues of significant concern and other minor items for which we request additional clarity in the regulatory text consistent with our understanding of EPA's stated intention in the preamble and where appropriate offer potential recommended solutions.

Please do not hesitate to contact me, Wendy Kirchoff (281-386-7324), or Rebecca Denney (972-989-3912), if you have questions or need additional information on any of these items. We look forward to continued collaboration.

Sincerely,

Wendy Kirchoff

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Detailed Comments on

Environmental Protection Agency’s (EPA’s)
“Waste Emissions Charge for Petroleum and Natural Gas Systems”
at 89 Fed. Reg. 5318 (January 26, 2024)

Docket ID No. EPA–HQ–OAR–2023–0434

March 26, 2024

I. EPA should amend the Facility Methane Emissions calculation to define the WEC Facility Methane Emissions as the portion of the emissions attributable to the natural gas sent to sales or facility throughput.

Clean Air Act (CAA) section 136(c) instructs the Administrator to "impose and collect a charge *on methane emissions that exceed an applicable waste emissions threshold* [emphasis added] under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to Subpart W of part 98 of title 40, Code of Federal Regulations, regardless of the reporting threshold under that subpart." Subsection (f) defines such a threshold as a "charge on the *reported metric tons of methane emissions from such facility that exceed (A) 0.20 percent of the natural gas sent to sale from such facility; or (B) 10 metric tons of methane per million barrels of oil sent to sale from such facility* [emphasis added], if such facility sent no natural gas to sale" or, similarly for nonproduction petroleum and natural gas systems, a "*charge on the reported metric tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facility* [emphasis added]."

A plain reading of CAA sections 136(c) and (f) clearly indicates that the methane emissions subject to evaluation against the Waste Emission Threshold for a given segment are those emissions attributable to the specifically listed product (e.g., natural gas sent to sale from a natural gas production facility, oil from an oil producing facility, natural gas sent to sale through a nonproduction petroleum and natural gas system). But EPA went beyond the statutory text, fundamentally changing its meaning with its addition of the word "all" when it proposed "to interpret 'reported metric tons of methane emissions' to mean *all reported methane emissions from a facility*, as reported under Subpart W." 89 Fed. Reg. at 5327/2 (emphasis added).

This is not an appropriate implementation of the statutory text. Rather, the WEC Facility Methane Emissions should be those reported pursuant to Subpart W that are attributable to the relevant product in the segment Waste Emissions Threshold. This is the correct way to give force to all provisions of Section 136 because read together: Subsection (c) directs EPA to "impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f)," and subsection (f) in turn tells EPA what to do when "to imposing and collecting the charge under subsection (c)." EPA should "impose and collect the charge on the reported metric tons of methane emissions from such facility that exceed—

a) 0.20 percent of the natural gas sent to sale from such facility; or
b) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale."

EPA does not identify its authority to impose and collect a charge on emissions other than those specifically referenced in (f)(A) and (B), nor does the text of Section 136 provide any.

Therefore, wherever there is natural gas sent to sale from the facility, the quantity of methane emissions in the numerator should reflect the total methane emissions attributable to the quantity of natural gas sent for sale represented in the denominator. This is managed in the commonly adopted

Natural Gas Sustainability Initiative (NGSI) protocol[1] on an energy allocation basis by multiplying the methane emissions by a gas ratio, which is defined as the energy content of the produced gas divided by the energy content of total produced hydrocarbons (values already reported through Subpart W filings) as shown below in equation 1.

$$Intensity\ IRA = \frac{CH_4\ emissions * Gas\ ratio}{sales\ natural\ gas}, \text{ where} \tag{1}$$

Gas ratio = energy content of produced gas / energy content of total hydrocarbons

Such an approach conforms to the plain reading of the statute and is consistent with practices in the life cycle assessment (LCA) community as illustrated in the implementation of the California Low Carbon Fuel Standard (LCFS)[2] or renewable fuel standard for transportation fuels.

Allen et al.[3] illustrated the importance of including emissions allocation on an energy basis, even within a single basin. In that work, the Eagle Ford Shale is analyzed across 12 subregions, ranging from primarily oil production to primarily dry gas production. When energy allocation is considered, similar methane intensities are observed across all subregions, but when all emissions are attributed solely to the natural gas portion of production (as is inherent in a metric lacking product allocation), the oil producing regions were significantly disadvantaged by as much as an order of magnitude with an unallocated methane intensity metric. This is because without energy allocation, the assessment is inherently biased: the methane associated with the total fluids production is included in the numerator (methane associated with oil AND gas production) but only the gas portion of the total sold is used in the denominator.

This bias is illustrated in Figure 1 below, where assets reported into the GHGRP for reporting year 2022 are plotted on a methane per energy intensity basis, as a function of production energy. Each dot in the figure represents a single reported facility (production and gathering and boosting facilities have been aggregated to single facilities when reported separately by the same reporting entity within a single region). Where methane emissions exceed the WEC threshold (0.2% of reported gas to sales for production and 0.05% of gas throughput for boosting and gathering), the dot is colored blue. Where methane emissions are less than the WEC threshold, the dot is colored green. The WEC threshold for production is overlaid as a red line, where 0.2% of a purely gas producing asset corresponds to 38.4 MT methane/btu.

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[1] https://www.eei.org/issues-and-policy/NGSI

[2] California Air Resources Board. California Low Carbon Fuel Standard. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard

[3] Allen, David T.; Chen, Qining; Dunn, Jennifer B. “Consistent Metrics Needed for Quantifying Methane Emissions from Upstream Oil and Gas Operations.” Environ. Sci. Technol. Lett., 2021, 8, 4, 345-349.

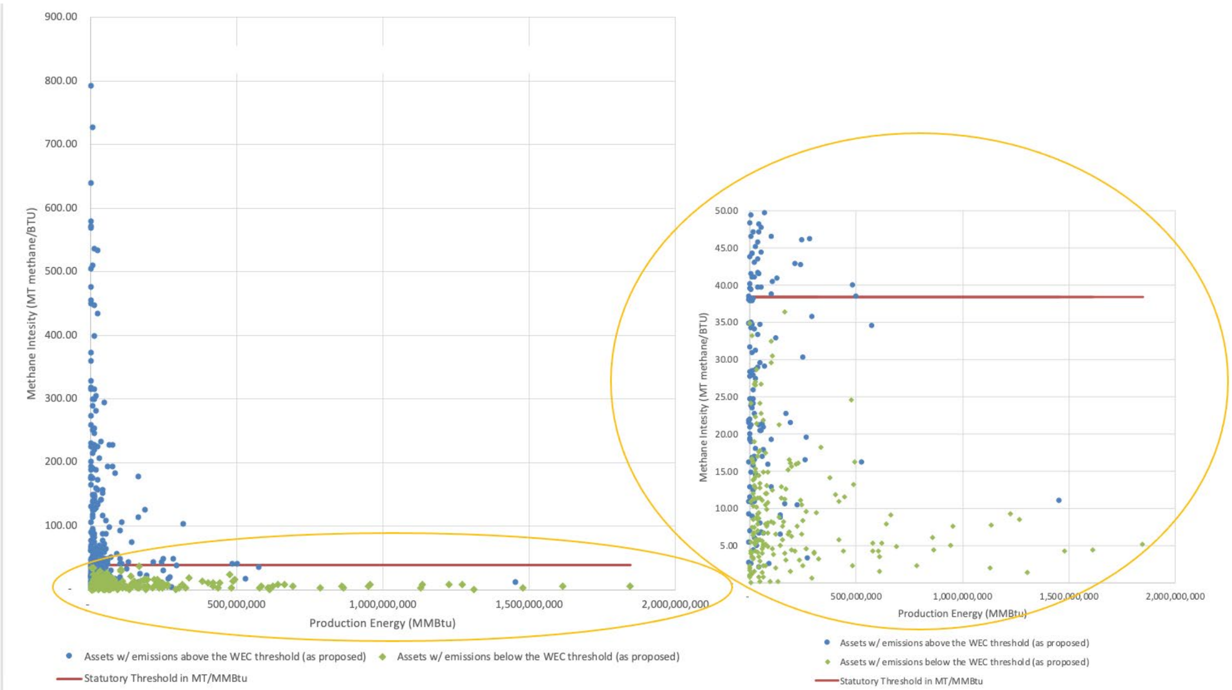

Figure 1 – *Emissions intensity as a function of production energy for the 2022 reporting year pursuant to Subpart W disaggregated by assets below and above the WEC threshold calculated as proposed, attributing all Subpart W emissions to gas only (except where no gas is sent to sale).*

In all cases, assets with high methane intensity on an energy basis exceed the WEC threshold. Most instances of low methane intensity on an energy basis fall below the WEC threshold. There are a handful of cases where assets with *low* methane intensity on an energy basis *exceed* the WEC threshold. In all of these cases, the operator largely produces energy in the form of oil and/or NGLs. In fact, as Table 1 shows, the average percent of energy sold derived from gas for the subset of assets that are low methane intensity on an energy basis but also above the asset WEC threshold is 30% compared to 67% of energy sold derived from gas for all assets and 73% for the assets that are low methane intensity and below the WEC threshold.

Intensity	WEC Threshold	% of Energy Produced as Natural Gas
Low[1]	Under	73%
Low[1]	Above	30%
All	All	67%

Notes:

1. *Low is considered to be less than 38.4 MT methane/btu which is equal to 0.2% when converted.*
2. *All data sourced from EPA Facility Level GHG Emission Data*

Table 1: *Analysis of intensities, the WEC threshold, and energy production from natural gas.*

Additionally, the language of CAA Section 136 focuses on minimizing waste. *See* Sec. 136(a)(3)(B), (C) (providing funding for “improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions *and waste*; ... supporting innovation in reducing methane and other greenhouse gas emissions *and waste* from petroleum and natural gas systems") (emphases added); 136(c) (titling the program that the proposal implements the "Waste emissions charge"); 136(f) ("Waste emissions threshold"); 136(h) (directing EPA to revise Subpart W to ensure that reports thereunder "accurately reflect the total methane emissions *and waste emissions* from the applicable facilities") (emphasis added).

This last passage is an especially strong signal that EPA, as explained above, is not to impose and collect WEC charges on *all* methane emissions, but rather on the *waste* emissions that exceed the waste emissions threshold for the specific segments identified in Subsection (f), since this last passage reveals that Congress identifies "waste emissions" (on which the "Waste Emissions Charge" is to be imposed and collected) as a discrete subset of "total methane emissions."

If an operator were required to apply a purely natural-gas-based waste emissions threshold to all emissions associated with a liquids production facility, that operator would be perversely incentivized to waste (not sell) any associated gas, likely via flaring, simply to avoid the waste emissions charge from methane emissions incorrectly associated with a comparatively small volume of "gas sent to sales".

Moreover, the assignment of all methane emissions to the natural gas portion of production and processing suggests that US oil and natural gas liquids (NGLs) have a methane intensity of zero. In fact, there are facilities that emit methane and are exclusively dedicated to liquids production or processing. Congress clearly understood this and designated a specific waste emissions threshold for production facilities with no marketed natural gas. Another scenario was identified in EPA's preamble discussing gathering and boosting and processing facilities with zero reported throughput of gas. EPA correctly identified that there are a small number of gathering and boosting and natural gas processing facilities that emit methane and report under Subpart W, but do not send gas to sales. Under the current proposed implementation of the statute, these facilities, which in general exclusively, or almost exclusively, handle NGLs or oil, with no reported throughput of natural gas to sales, are incorrectly considered in excess of the waste emissions threshold for any and all reported emissions.

Applying an energy allocation basis would resolve this issue by allocating emissions based on energy of products received by the facility, where these volumes are already reported to the GHGRP through Subpart W.

EPA indicates it is aware of other approaches for calculating "methane intensity" using energy allocation methods, but suggests that its proposal is more practical since the proposed approach "can be implemented with data currently reported under Subpart W" and other methods would increase operator burden. Setting aside the aforementioned disproportionate financial burden looming over operators producing or handling liquids rich assets relative to those producing or handling principally dry gas under the current proposal, the necessary information to apply an energy allocation to the facility emissions tabulation are also already currently reported under Subpart W.

Data reported under Subpart W for production facilities include:

- Quantity of gas produced in the calendar year from wells (thousand standard cubic feet) [98.236(aa)(1)(i)(A)]
- Quantity of gas produced in the calendar year for sales (thousand standard cubic feet) [98.236(aa)(1)(i)(B)]

- Quantity of crude oil and condensate produced in the calendar year for sales (barrels) [98.236(aa)(1)(i)(C)]

Data reported under Subpart W for boosting and gathering facilities include:

- Quantity of gas received by the gathering and boosting facility in the calendar year (thousand standard cubic feet) [98.236(aa)(10)(i)]
- Quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year (thousand standard cubic feet) [98.236(aa)(10)(ii)]
- Quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year (barrels) [98.236(aa)(10)(iii)]
- Quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year (barrels) [98.236(aa)(10)(iv)]

EPA says that operators would need to collect and report additional detailed information on all of the constituents of the natural gas and other hydrocarbons in order to apply an energy allocation approach. However, just as EPA proposed to consistently apply the density of methane to the natural gas quantity irrespective of small variations in sales gas composition, EPA could also include standard, representative energy conversion factors to apply to the reported quantities of gas and liquid products. Such an approach would allow uniform, representative allocation of emissions by product using widely accepted standard values. AXPC recommends energy conversion factors of 5.7 million BTU (MMBtu)/barrel for liquids and 1.0 million BTU (MMBtu)/thousand SCF (Mcf) of gas.[4]

II. EPA should clarify that a parent company may function as a common WEC obligated party for the WEC applicable facilities of its subsidiaries and may choose to include facilities that fall under the 25,000 tons CO_2e applicability threshold.

EPA proposes that netting may occur only across entities that have the same owner or operator. However, in many of the segments (for example, onshore and gathering and boosting), the term ‘operator’ is very specifically defined and reflects one, very specific operator. Often this is an entity that is established for operation in a particular region or in a particular industry segment. Thus, many times, the name of the entity operating the onshore production assets will be different (although under the same parent and company umbrella) as the entity operating gathering and boosting assets. In other cases, an entity operating the onshore production assets in one basin will be different than the operator of onshore production assets in another basin. Thus, limiting netting to the same operator will likely have the effect of significantly reducing or eliminating the ability for operators to use the intended netting provision.

Additionally, companies often retain the name of a legacy operating company even after acquiring assets, even though the new “parent company” ultimately makes capital allocation decisions, consolidates for tax purposes, etc. – leaving the subsidiary to manage daily operations. In some cases,

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[4] https://www.eia.gov/energyexplained/units-and-calculators/ with cited source Data source: *Monthly Energy Review*, May 2023; preliminary data. Prices are nominal prices (not adjusted for changes in the value of the U.S. dollar). https://www.eia.gov/totalenergy/data/monthly/pdf/sec12_3.pdf

there may be a corporate structure that acquires a company or asset to be a wholly or partially owned subsidiary. In these instances, there may be multiple operators of WEC applicability facilities that are owned by the same parent company – the company that ultimately has control over operations of the WEC applicable facility. A company should be able to net across assets over which it has control of the operations. Precluding such netting across assets provides no incentive for companies to find reductions anywhere they can in order to reduce overall methane emissions. For example, certain operations, areas, or regions may have better access to electricity. Assets in those areas or regions are better positioned to reduce methane emissions through electrification. Operators should be encouraged to find those reductions in areas where they can, even in areas where the WEC applicable facility is already below the WEC threshold. Allowing netting across subsidiaries within parent companies will allow for this. Similarly, where operators have both onshore and gathering and boosting operations, the ability to net where owned by the same parent can encourage creative and thoughtful planning and design to reduce emissions along the natural gas value chain where most available and in places that can achieve the greatest reductions. Restricting netting is inadvertently setting a “floor” for emissions reduction by disincentivizing reduction below the legislatively established thresholds established in the IRA which was not the intent of Congress.

This is consistent with EPA’s goal of aligning reporting requirements under Subpart W, both in terms of timing and responsibility. AXPC’s proposal would maintain a reporting structure where facilities, as reported under Subpart W, remain intact as WEC obligated facilities. And each reported facility should have an individual owner or operator responsible for reporting and filing the WEC. However, such entities should be able to net with any sister companies. Circumstances described above, such as discrepancies in naming conventions or for a legacy corporate name that may persist in Subpart W designated representative representations, should not limit aggregation of WEC applicable facilities into a single WEC filing by a single WEC obligated party. Furthermore, to the extent that a company voluntarily reports facilities that fall under the 25,000 tons CO_2e applicability threshold, those facilities should also be included as a WEC applicable facility. AXPC recommends that EPA clarify that a parent company may function as the WEC obligated party for the WEC applicable facilities of its subsidiaries.

III. EPA’s proposed reporting deadlines associated with the WEC are unreasonable and should be revised in two important ways: 1) The WEC filing and payment deadline should be 30 days after EPA concludes its Subpart W data verification activities or November 1 of each year, whichever comes later, and 2) the proposed deadline to disallow part 99 resubmissions after November 1 of the year following the reporting year should apply to EPA requests for revisions in addition to operators’ voluntary resubmission.

Under 40 CFR 98 Subpart W, GHG emissions and data are due to the EPA on March 31 of the following year. Historically, EPA continues to review and require changes to Subpart W submissions months and even years after the submittal deadline. In this regard, we note that Congress has not given EPA direction with respect to when it should require obligated parties to submit their WEC payments. Subsection 136(g) provides only that “[t]he charge under subsection (c) shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter.” In stark contrast, subsection (h) *does* provide a date certain by which EPA is to finalize its revisions to Subpart W. This contrast shows that Congress wished EPA to have timing flexibility on when WEC charges are to be imposed and collected.

But EPA's proposed rule does not acknowledge Congress's silence in this respect, nor does it give any explanation for proposing to align WEC payment dates with Subpart W filing dates, *see* 89 Fed. Reg. at 5350. Requiring companies to submit the WEC filing and remit applicable WEC obligation on the same day will result in numerous instances of refiling and confusion - particularly as implementation of revised Subpart W requirements and provisions occurs.

Companies should submit their WEC filings and EPA should complete any verifications and/or audits before companies are required to submit their WEC obligation payments. EPA has stated that companies must submit any revisions to their WEC filings by November 1st of the year after the reporting year (i.e., approximately 7 months after the WEC filing). EPA has indicated that changes to the WEC filings (with limited exceptions for submitting exemption report information) cannot be made by the operator after that date. If this deadline is imposed on operators as a deadline after which revisions may not occur, that same deadline should apply to EPA. Thus, if EPA does not request corrections before November 1, the GHG reported emissions are final.[5]

EPA in its final rule should provide that WEC obligation payments are due within 30 days of that November 1st date. This approach will avoid creating unnecessary burden on both the agency and reporters to track, modify, and in some cases reimburse payments in response to EPA or an operator's identified need for revisions to a submitted report, as commonly occurs in the program including for many accepted and compliant reasons. This staggered WEC filing and WEC obligation timeline (with a half year to complete any revisions – whether by EPA or the operator) will also eliminate potential complications with the three types of financial sanctions (i.e., two different potential interest payments and administrative penalties) that could result from a timely but inaccurate WEC obligation payment at the time of the WEC filing. While AXPC understands EPA's desire to incentivize accurate reporting, the reports that are required under Subpart W and form the basis of the WEC filing are among the most extensive in the country. These could require – for a particular WEC applicable facility – thousands to tens of thousands of calculations. AXPC is aware of no other reporting scheme with that level of detail. Operators work diligently to file accurate statements, but there is an inherent risk of minimal and generally inconsequential mistakes based upon the shear extent and scope of reporting. Such dynamics are often further complicated by other dynamics such as mergers and acquisitions of companies and/or assets. Penalties should not be assessed due to good faith but erroneous efforts. Delaying the obligation to pay the WEC fee until after WEC filings are deemed complete and finalized will eliminate such outcomes and avoid the needless confusion and dedication of resources from agency and operator alike that will otherwise incur should the timing of WEC obligations be finalized as proposed.

IV. EPA should allow operators to provide empirical data as part of the WEC filing, consistent with Congressional intent.

AXPC urges EPA to allow operators, upon their election, to utilize a mechanism by which to provide empirical data as part of the WEC filing that demonstrates that an emission factor or factor for a particular piece of equipment overestimates emissions and that empirical data appropriately reflects a

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[5] AXPC believes that any audits should be completed by this November 1st date. If EPA does not adopt the proposal to complete audits by November 1st, there must be a date certain by which EPA can no longer conduct an audit, EPA must have a basis to believe there are significant errors before requiring an audit, and EPA should not impose any penalties for revised WEC obligations or should provide opportunities and bases for waiving any penalties.

lower waste emission charge obligation. Providing such an opportunity is consistent with Congress's directive to EPA to update Subpart W to reflect empirical data.

V. EPA should develop an approach that ensures the availability and utility of the intended exemption for regulatory compliance

Under the Inflation Reduction Act (IRA), Congress exhibited a clear intent to require that EPA provide an exemption from the WEC for applicable facilities that are subject to and in compliance with certain CAA 111(b) and (d) regulations (herein the "Regulatory Compliance Exemption"). Specifically, Congress provided that:

> Charges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 7411 of this title upon a determination by the Administrator that—
>
> > (i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 7411 of this title have been approved and are in effect in all States with respect to the applicable facilities; and
> >
> > (ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 Fed. Reg. 63110 (November 15, 2021)), if such rule had been finalized and implemented.
>
> 42 U.S.C. § 7436(f)(6).

Congress could not have intended for the exemption to be essentially unattainable. However, as proposed, EPA's implementing rule will eviscerate the Regulatory Compliance Exemption. Under the terms of the proposal, the Regulatory Compliance Exemption would not be available for *at least* three years (because, in the final methane rule, this is how long EPA has allowed for states to submit their 111(d) plans and for EPA to review and approve or disapprove them) and once available, will be virtually impossible to achieve (particularly for the onshore and gathering and boosting sectors) – thus, giving no meaningful effect to Congress's intent to provide a Regulatory Compliance Exemption. In other words, EPA has effectively interpreted the Regulatory Compliance Exemption out of the statute. *Zadvydas v. Davis*, 533 U.S. 678, 696 (2001) (if Congress made its intent clear in the statute, courts "must give effect to that intent"); *cf. Kosak v. United States*, 465 U.S. 848, 854 (1984) (a court should not interpret a statute to "nullif[y]" a portion of the statute "through judicial interpretation").

EPA must revise the final rule and preamble to, among other things:

(1) Accurately reflect Congressional intent with respect to the regulatory compliance exemption;
(2) Remove unsupported assumptions regarding whether facilities subject to methane regulations will be above or below the WEC thresholds;
(3) Limit noncompliance to emissions limits and work practice standards;

(4) Limit noncompliance to those circumstances where enforcement actions result in penalties and a determination that the WEC Regulatory Compliance Exemption is unavailable;
(5) Ensure that EPA can determine availability of the Regulatory Compliance Exemption upon adoption of each state or federal OOOOc plan; and
(6) Ensure that EPA makes equivalency determinations (particularly with respect to NSPS OOOOb) immediately.

a) EPA misinterprets Congress's intent with respect to the regulatory compliance exemption

EPA states that it believes the Congressional intent of the Regulatory Compliance Exemption was two-fold: (1) to be implemented such that the WEC acts as a bridge to full implementation of the NSPS OOOOb and EG OOOOc by encouraging methane reductions in the near term while state plans are being developed; and (2) encouraging timely implementation of requirements in state and federal plans. EPA then uses this interpretation of Congressional intent as the basis for additional erroneous conclusions – namely, (1) that no operator may avail themselves of the Regulatory Compliance Exemption until all states (and the federal government, as necessary) have had OOOOc plans approved by EPA (for state plans) or promulgated federal plans (herein "state and federal OOOOc plans") and (2) that EPA must wait until all state and federal OOOOc plans are approved or promulgated to determine whether those NSPS OOOOb and EG OOOOc plans will affect equivalent emissions reductions as the proposal from November 2021 would have done.

EPA provides no explanation for how the plain reading of the statutory text supports its conclusion. The statute, on its face, provides no indication of such an intent, and states no such reasons for the basis of the exemption. However, exemptions from the fee were clearly intended to reward and incentivize compliance with the regulations – regulations that were themselves designed to reduce emissions.

Further, EPA cites no legislative history to support its position, and the legislative history that exists does not support EPA's interpretation of Congress's intent. Rather, the legislative history provides that the WEC is intended to reduce methane emissions, create a clean energy technology bank, and fund wildlife resiliency efforts and clean energy infrastructure. 168 Cong. Rec. H7577-02 (2022). In contrast, EPA's reading suggests that the primary intent of the Inflation Reduction Act in implementing the WEC was to address gaps in timing of finalization of NSPS OOOOb and state and federal OOOOc plans. Nothing in the legislative history supports such an interpretation. A more realistic interpretation is that the Regulatory Compliance Exemption was intended to provide an exemption for entities that were otherwise incurring the costs associated with complying with extensive methane emissions reduction requirements. If the intent had been for the WEC to function as a bridge until finalization of NSPS OOOOb and state and federal OOOOc plan, then Congress would have eliminated the WEC upon such occurrence. However, Congress did not propose such elimination and thus, there is no evidence that the WEC was intended to act as a bridge to anything.

Even if EPA were correct that Congress intended to incentivize quicker implementation of state and federal OOOOc plans, EPA's interpretation of the Regulatory Compliance Exemption works directly against any such intent. If *no* states' WEC Applicable Facilities may enjoy the benefit of the Regulatory Compliance Exemption until *all* state and federal OOOOc plans have been adopted, there is simply no incentive for states to adopt and obtain approval of their plans more quickly. This is particularly true given that different states will have different resources available, differing levels of experience with rulemaking, and other factors that may make development of a OOOOc plan more or less difficult.

And as we explain in more detail below in Section V(f) and (g), EPA's reading of the statutory text in this regard is not plausible. Instead, the proper reading of the text requires that a WEC Applicable Facility should be eligible for the Regulatory Compliance Exemption once all states within which the WEC Applicable Facility has affected or designated facilities have a state or federal OOOOc plan in effect.

b) EPA provides no basis for its conclusion that facilities compliant with NSPS OOOOb and EG OOOOc will likely be below the WEC thresholds

EPA states that:

> WEC applicable facilities containing CAA section 111(b) and (d) facilities that are in compliance with the applicable standards are likely to have emissions below the thresholds specified in section II.B of this preamble due to mitigation resulting from meeting the methane emissions requirements of NSPS OOOOb or EG OOOOc-implementing state and Federal plans and therefore would not be expected to incur charges under the WEC program.

89 Fed. Reg. at 5323. EPA provides no basis for its conclusion on such a technical issue. The WEC will be based on emissions intensity factors that are set forth in the statute. NSPS OOOOb/EG OOOOc do not contain emissions intensity requirements. Rather, they contain command and control regulations that mandate emissions standards and work practice standards designed to target reductions from specific units or equipment. EPA has provided no nexus or correlation between the emissions reductions expected from NSPS OOOOb/EG OOOOc and the emission intensity thresholds established in the IRA that support or justify its conclusions. Whether EPA's conclusion proves accurate in some instances (or even many) is irrelevant. EPA should not make such broad statements or conclusions (which may then be used to set expectations regarding emissions from NSPS OOOOb/EG OOOOc subject facilities).

AXPC does not believe that Congress had any understanding as to whether compliance with NSPS OOOOb/EG OOOOc would result in most facilities being below the waste emissions charge threshold. In fact, the existence of the Regulatory Compliance Exemption suggests that Congress expected otherwise. While EPA acknowledges that there will be some applicable facilities that are complying with NSPS OOOOb and EG OOOOc that are above the waste emissions thresholds, EPA appears to suggest that these would be limited exceptions. And EPA's apparent expectation that these will be limited exceptions then appears to support its creation of a rigorous, unattainable Regulatory Compliance Exemption. In short, EPA ignores the consequences that may result from implementing the Regulatory Compliance Exemption such that it is unachievable and likely underestimates the number of applicable facilities that are substantially and materially in compliance with NSPS OOOOb/EG OOOOc yet will still owe substantial fees under the WEC.

EPA cannot conclude that facilities compliant with NSPS OOOOb and EG OOOOc will not be subject to the WEC based on whims. It must provide specific evidence to support a technical conclusion and should not establish inaccurate and erroneous expectations regarding whether and how NSPS OOOOb and EG OOOOc will specifically relate to the waste emissions thresholds. Here, there is no reason that EPA needs to arrive at this conclusion and AXPC requests that EPA withdraws its unfounded statements.

AXPC provides several reasons that it believes EPA's conclusion is not only unsupported but ignores recent changes that EPA itself has proposed to Subpart W and the potential consequences for WEC

Applicable Facilities. To the extent that EPA relied upon any data in arriving at its conclusion, it appears likely (given that recent proposed changes to Subpart W have not yet been finalized) that EPA was basing any conclusions on existing Subpart W reporting and emissions factors in existing Subpart W. See Regulatory Impact Analysis of the Proposed Waste Emission Charge at 2-4. However, as noted in AXPC and other industry stakeholder comments on the proposed revisions to Subpart W, EPA has proposed to substantially increase certain emissions factors for certain equipment – including equipment that either will be difficult to mitigate or that is not equipment addressed by NSPS OOOOb/EG OOOOc (see e.g., use of pilot flame monitoring data, flowback estimates, among others). As noted in comments from AXPC and other industry stakeholders on Subpart W, EPA's proposed revisions to Subpart W will likely now result in the overestimation of emissions in certain categories – and these overestimated emissions may well result in many operators being above the WEC threshold – even for WEC Applicable Facilities that are materially compliant with NSPS OOOOb/EG OOOOc.

These considerations are one of the key reasons that AXPC and other industry stakeholders have been requesting that EPA take a more thoughtful and coordinated approach with respect to Subpart W revisions and the WEC rule. These issues are inherently tied together, and Congress specifically directed EPA to undertake the difficult work of coordinating the two – in part to ensure that an accurate inventory is being submitted. Specifically, Congress required that:

> [n]ot later than 2 years after August 16, 2022, the Administrator shall revise the requirements of Subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.
>
> 42 U.S.C. § 7435(h).

AXPC does not believe that many of the proposed revisions to Subpart W appropriately reflect emissions and will in fact overstate emissions. For example, Subpart W proposes to allow operators to only account for combustion efficiencies of either 92 or 95 percent for flares and enclosed combustion devices depending on whether the combustion devices must comply with NSPS OOOOb/EG OOOOc control device requirements. Both values are too low in light of the rigorous control device requirements in NSPS OOOOb/EG OOOOc and recent studies. At a minimum, these revisions and increased factors have not likely been considered by EPA in its unsupported statements regarding the relationship between NSPS OOOOb/EG OOOOc and an emissions intensity threshold. EPA must take a step back and ensure that its efforts regarding amendments to Subpart W and its finalization of the Proposed Rule are coordinated, thoughtful, and consistent.

AXPC also incorporates by reference its comments filed on the proposed revisions to Subpart W in this regard, *see* EPA-HQ-OAR-2023-0234-0295 at page 28, and reproduces them here due to concern that EPA may take the position that incorporation by reference is not a sufficient means of placing them before EPA in this rulemaking docket. EPA obviously did not heed these comments, but neither has it given any explanation in the instant proposal why it can disregard them and continue to treat the Subpart W and WEC rulemakings as separate rulemakings in violation of the statute and the fundamental obligation to conduct its rulemakings in a rational manner.

We particularly reiterate from our Subpart W comments the following observations: As a threshold matter, EPA cannot legally or rationally treat the Subpart W rulemaking as separate and independent from its forthcoming proposed implementation of the MERP's "waste emissions charge program." ... Congress did not intend EPA to proceed this way. To the contrary, it directed EPA to make revisions to Subpart W so that both reporting under Subpart W and the calculation of WEC meet certain criteria. When submitting Subpart W comments, regulated companies were in the dark as to how EPA would interpret and implement the WEC program. And now, operators remain in the dark regarding how EPA will finalize amendments to Subpart W. This deprives them of the substance of their right to provide informed comment on the significance of the current Proposed Rule with regard to how the changes EPA plans for Subpart W will interact with EPA's implementation of the WEC.

c) EPA's implementation of the regulatory compliance exemption should evaluate compliance only with the emissions limits and work practice standards in NSPS OOOOb and EG OOOOc (and state and federal plans thereunder)

EPA acknowledges that CAA 136(f)(6)(A) does not specify the definition of compliance for the purposes of the exemption, and notes that many different types of compliance deviations or violations can occur. EPA proposes that under the Regulatory Compliance Exemption, a WEC applicable facility must be in full compliance with the methane emissions requirements of the applicable NSPS (OOOOa and OOOOb) and state and federal OOOOc plans at all affected and designated facilities contained within that WEC applicable facility. 89 Fed. Reg. at 5344-45. EPA interprets full compliance as no deviations or violations from the requirements, including quantitative emissions limits, work practice standards, monitoring, recordkeeping, and reporting. EPA bases its interpretation on the lack of "mitigating language" and its interpretation that Congress intended the reference to compliance with requirements to mean all requirements. However, EPA does not provide reasoning or support for why the variation in types of requirements means that they all must be considered in relation to the regulatory exemption for the methane emissions charge. EPA cannot merely point to the absence of definitional language, without considering the purpose of the statute; properly considering statutory purpose suggests that Congress did not intend that the regulatory compliance exemption required compliance with *all* requirements listed in the NSPS.

EPA's finalization of this proposal should provide that the Regulatory Compliance Exemption will be assessed only against NSPS OOOOb and EG OOOOc, not against NSPS OOOOa or any future potential NSPS or EG methane regulations on this sector under CAA section 111. EPA only mentions its proposal to assess compliance status for purposes of the regulatory compliance exemption with respect to NSPS OOOOa once, 89 Fed. Reg. at 5344, and EPA does not offer any statutory construction or other substantive discussion of why it proposes to include NSPS OOOOa in its regulatory-compliance assessments. The proper reading of the statute is that Congress did not intend EPA to do so.

While it is true that the introductory clause of CAA 136(f)(6)(A), viewed in isolation, speaks generally of "methane emissions requirements pursuant to subsections (b) and (d) of section 7411," these words must be read in context. The sub-provision at CAA 136(f)(6)(A)(ii) refers specifically to the November 2021 proposal of what has recently been finalized as NSPS OOOOb and the accompanying EG OOOOc, and *these* are the requirements to which Congress refers in the root text of CAA 136(f)(6)(A). Furthermore, while we disagree with EPA that Congress intended the Regulatory Compliance Exemption to incentivize quicker adoption of requirements under state or federal OOOOc plans, we observe that this construction of the statute proceeds from the same assumption as our reading does here: that Congress in the Regulatory Compliance Exemption contemplated assessing eligibility for that exemption against the rulemaking initiated with the November 2021 proposal, and not for other standards.

Proceeding as EPA proposes and assessing compliance against NSPS OOOOa in addition to the regulations Congress intended will create confusion. State plans should address the relationship between facilities that are NSPS OOOOa and those that are subject to the state OOOOc plan. State plans will provide implementation timeframes for facilities to come into compliance with the OOOOc plans, and EPA has appropriately concluded that those requirements only need be in place, not implemented, to qualify for the Regulatory Compliance Exemption. However, to the extent that an NSPS OOOOa affected facility remains as such until actual implementation of the OOOOc requirements, there could be a period of time where OOOOa continues to apply after EPA has signed off on the Regulatory Compliance Exemption. NSPS OOOOa compliance should not be part of the analysis in determining whether the Regulatory Compliance Exemption is available during that period.

While it is clear why requirements such as monitoring, reporting, and recordkeeping are part of sections 111(b) and 111(d), they need not be applied to determine compliance for purposes of this exemption. Considerations such as monitoring, recordkeeping, and reporting, while required by CAA section 111, should not be included in determinations of compliance for the Regulatory Compliance Exemption because they do not directly impact emissions or the amount of emission reductions.

The plain language of the statute, and Congress's intent, clearly demonstrate that the purpose of the emission charge and the regulatory compliance exception is to incentivize facilities to reduce actual methane emissions. Since the focus is on the actual levels of emissions, and less on the process requirements such as recordkeeping, reporting, and monitoring, compliance should be established where an operator has met all quantitative limits and work practice standards. This is in line with the calculation process for the charge which determines the charge based on the metric tons of methane emissions above the threshold requirement. A deviation in monitoring, recordkeeping or reporting will not impact this calculation, and thus should not impact whether an operator is in compliance for the exception.

This is evidenced by EPA's discussion of the demonstration that it will make to meet Clause (ii) (as described below). Specifically, EPA notes that Congress directs EPA to compare the emissions that would have been achieved if the NSPS OOOOb/EG OOOOc 2021 Proposal were finalized against the finalized NSPS OOOOb/EG OOOOc. This evidences that Congress was focused on the *emissions reductions* that the NSPS OOOOb/EG OOOOc would achieve (through emissions standards or work practice standards), not on requirements related to monitoring, recordkeeping, and reporting. Thus, only those provisions of NSPS OOOOb and state or federal OOOOc plan that constitute an emission limits or the non-recordkeeping and reporting provisions of a work practice standard should be considered in determining eligibility for the Regulatory Compliance Exemption.

d) EPA must revise the reporting requirements for the regulatory compliance exemption and must not base availability of the regulatory compliance exemption on self-reported deviations

EPA's Proposed Rule indicates that in order to obtain the Regulatory Compliance Exemption a facility must have no deviations or violations of the methane emissions requirements (including monitoring, recordkeeping, and reporting) promulgated pursuant to NSPS OOOOb or state or federal OOOOc plans. EPA proposes that operators represent this status and appears to require reliance on operators' annual reporting requirements under the NSPS to require operators to self-report whether there are deviations or violations of the methane emissions requirements. AXPC strongly disagrees with numerous aspects of this proposal by EPA.

First, operators should not be required to report unless they are seeking a Regulatory Compliance Exemption. If an operator knows that it cannot obtain the Regulatory Compliance Exemption (either because its emissions are below the WEC thresholds or because an operator has itself concluded that it cannot meet the Regulatory Compliance Exemption), then that operator should be able to elect not to report and acknowledge that it does not seek the Regulatory Compliance Exemption. EPA should not mandate reporting by individuals that are not seeking the Regulatory Compliance Exemption – either because they are not eligible or because they cannot obtain it. An exemption is precisely that: an exemption. If an operator does not want an exemption (whether the Regulatory Compliance Exemption, the permitting delay exemption or the plugged well exemption), then EPA should not require an operator to submit any materials regarding that exemption.

Second, deviation reporting may not always reflect a violation appropriate for pursuit of enforcement or may often not reflect noncompliance that should result in ineligibility for the Regulatory Compliance Exemption. Rather, a determination of noncompliance should be based only on those circumstances where an operator has an enforcement action that has resulted in penalties for noncompliance with emission limits and work practice standards under NSPS OOOOb or state or federal OOOOc plans **and** where EPA has determined that such enforcement action precludes eligibility for the Regulatory Compliance Exemption. By limiting noncompliance to those circumstances where an operator and relevant authority have entered into a settlement agreement requiring the payment of penalties or an adjudication resulting in payment of penalties, EPA would ensure proper and fair due process under the law. Further, requiring either the settlement agreement or the adjudication to include a finding regarding the availability of the Regulatory Compliance Exemption would allow EPA to utilize its discretion to acknowledge when deviations or violations are not substantively or materially impacting emissions such that an operator should retain eligibility for the Regulatory Compliance Exemption.

Establishing such a basis for determining eligibility for the Regulatory Compliance Exemption is needed to ensure that EPA does not inadvertently disincentivize self-audits or self-investigation or unduly punish operators who embrace a rigorous deviation reporting program. EPA invested significant time over the last 5 to 10 years to develop programs and incentives for operators in the oil and gas sector to complete self-audits on their existing assets or on newly acquired assets. EPA's interpretation of the Regulatory Compliance Exemption – i.e., that all deviations or violations identified by the operator itself will preclude eligibility – will strongly disincentivize self-audits.

The statutory text leaves room for EPA to determine the extent and meaning of the term "in compliance." Here, EPA has elected in its proposed rule to interpret the term in such a manner that it makes the exemption fundamentally unavailable. This is particularly true for the onshore and gathering and boosting sectors where each WEC applicable facility has dozens to thousands of affected and/or designated facilities/sites within its boundaries. It is unclear whether Congress understood in adopting the WEC provisions of the IRA that onshore and gathering and boosting applicable facilities can contain dozens to thousands of affected and/or designated facilities. It makes no logical sense that Congress would intend that a deviation at one affected facility (e.g., one storage tank) would then make ineligible for the Regulatory Compliance Exemption the remaining thousands of storage tanks that are in compliance within that same basin. Certainly Congress intended that the Regulatory Compliance Exemption be available to all operators subject to the 111(b) and (d) requirements. EPA's current approach does not give effect to the statutory intent or requirement, and is therefore not a reasonable interpretation and application of the statutory text. AXPC's proposal would provide EPA and operators the ability to discuss and determine when noncompliance should preclude use of the Regulatory Compliance Exemption.

In addition, or in the alternative, EPA should develop a threshold or percentage of compliance (again only with respect to emissions limits and work practice standards) that a WEC applicable facility must achieve. EPA must provide meaningful opportunity for operators to obtain the Regulatory Compliance Exemption and flawless compliance should not be mandated in order to obtain the Regulatory Compliance Exemption. This is particularly true given that certain interpretations and requirements that EPA has established in NSPS OOOOb and EG OOOOc make strict and flawless compliance even with emissions standards and work practice standards virtually impossible. For example, EPA has proposed that any emission from a cover or closed vent system constitutes a deviation/violation of the standard. As AXPC and other parties noted in their comments on NSPS OOOOb/EG OOOOc, emissions cannot be precluded from covers or closed vent systems (even with complete and compliant design and operation). Unfortunately, as these interdependent rulemaking timelines overlap, commenters do not yet have a full understanding of whether, if and how these (and other) issues will be addressed by EPA or the courts in response to any reconsideration or review petitions (each of which would be filed after the close of this comment period). EPA must look for a path forward that does not mandate flawless compliance that is not practically achievable, in the same way this rule must not incorporate such a flawed expectation in order to obtain the Regulatory Compliance Exemption. AXPC has proposed one path here – i.e., limit the provisions to which the compliance demonstration applies and limit non-compliance to those that have completed the full enforcement process. In addition, or in the alternative, EPA should consider and adopt some other alternative that would give meaning and availability to the Regulatory Compliance Exemption.

e) EPA's discussion regarding netting of WEC applicable facilities creates significant confusion

EPA determines in the Proposed Rule that "if a facility's emissions are not subject to the WEC, either because the facility is not a WEC applicable facility, or because a WEC applicable facility receives the Regulatory Compliance Exemption,[6] that facility's emissions do not factor into the netting of emissions for a WEC obligated party." 89 Fed. Reg. at 5329. In other words, "only WEC applicable facilities may net, and only WEC applicable emissions may be netted." *Id*. Based on a related analysis, EPA further

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[6] AXPC notes that this discussion assumes the final adoption of a Regulatory Compliance Exemption that can be attained. As currently proposed, AXPC believes that no (or virtually no) WEC Applicable Facilities will be able to receive the Regulatory Compliance Exemption and this erroneous interpretation for facilities receiving the exemption will be irrelevant.

concludes that WEC Applicable Facilities with emissions below the waste emissions threshold are not eligible to receive the Regulatory Compliance Exemption. Thus, EPA apparently concludes that: (1) WEC Applicable Facilities with waste emissions above the threshold may receive the Regulatory Compliance Exemption but may not net; and (2) WEC Applicable Facilities with waste emissions below the threshold may not receive the Regulatory Compliance Exemption but may net. While this result appears to be a reasonably practical outcome with respect to netting and the Regulatory Compliance Exemption, EPA's position and its logic are confusing. Instead, EPA should encourage all WEC Applicable Facilities to both: (1) achieve emissions below the waste emissions threshold; and (2) to maintain compliance such that the WEC Applicable Facility is eligible for the Regulatory Compliance Exemption. EPA's stated interpretations do not on their face appear to support these goals. Instead, EPA should simply conclude that a WEC Applicable Facility that receives the Regulatory Compliance Exemption remains eligible to net (at the operator's election). In fact, AXPC believes that netting should always be at the option and discretion of the operator. There should be no forced netting. Rather, operators should be able to elect when to net (and as discussed above, should be able to net through parent companies). And, as noted above, operators should be able to voluntarily report Subpart W emissions for facilities that do not exceed the threshold and use those emissions for netting purposes.

AXPC agrees with EPA that nothing should require an operator of a WEC Applicable Facility that does not seek the benefits of the Regulatory Compliance Exemption to have to undertake the necessary resources to demonstrate compliance with the Regulatory Compliance Exemption. However, an operator should be able to make the demonstration that it meets the Regulatory Compliance Exemption even if it has emissions below the WEC threshold. This is important in the event that an operator submits emissions calculations below the WEC threshold but where subsequent calculations (either the operators or through the verification process at EPA) evidence emissions above the WEC threshold. In that case, an operator who was below the WEC threshold initially may need to subsequently rely upon the Regulatory Compliance Exemption.

f) Clause (i) of the regulatory exemption should be met for a WEC applicable facility once all state (or federal) plans covering that WEC applicable facility are approved (or promulgated)

As noted above, Congress identified two prongs that must be met in order for the Regulatory Exemption to be available for an operator of a WEC Applicable Facility. In the first prong (set forth in 42 U.S.C. § 136(f)(6)(A)(i)(herein "Clause (i)"), Congress indicated that Clause (i) requirements have been satisfied when "methane emissions standards and plans …. have been approved and ***are in effect in all States with respect to the applicable facilities***." (Emphasis added.) EPA proposes to interpret the words "are in effect[7] in all States with respect to the applicable facilities" as follows:

> The EPA further proposes to interpret ''all states'' in CAA section 136(f)(6)(A)(i) to mean that every state with an applicable facility (i.e., all states with Subpart W facilities containing CAA section 111(b) or (d) facilities) must have an approved plan (state or Federal) before the determination can be made.
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> 89 Fed. Reg. at 5337/3.

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[7] EPA interprets "in effect" as when an Administrator determination regarding a federal or state OOOOc plan has been made, not when the applicable requirements in the state and federal plans are fully implemented. As noted in Section V(g) below, AXPC agrees with this part of EPA's interpretation.

EPA claims that this approach is aligned with a plain reading of the statutory text. But this is not a reasonable interpretation of this statutory phrase, either on its own terms, in context, or when considering Congress's underlying purpose in enacting the Regulatory Compliance Exemption provision. First, as noted above, it directly contradicts what EPA itself says is a major purpose for the exemption: incentivizing timely implementation of state-plan requirements. While AXPC does not agree with EPA that the Inflation Reduction Act was intended to incentivize timely implementation of state-plan requirements, EPA's internal inconsistencies evidence the problems with its interpretations of the statutory language.

EPA's interpretation ignores a critical part of the provision – the modifier – "with respect to the applicable facilities." Statutes must be read as a whole, and the "cardinal principle of interpretation [is] that courts must give effect, if possible, to every clause and word of a statute." *Parker Drilling Mgmt. Servs., Ltd. v. Newton*, 139 S. Ct. 1881, 1890 (2019). The term "the applicable facilities" refers not to *all facilities* nationwide, but to the *specific* facilities whose eligibility for the Regulatory Compliance Exemption is in question. Giving meaning to all terms of the statute results in the conclusion that a facility is not eligible for the Regulatory Compliance Exemption until all states in which the applicable facility is located have a state or federal OOOOc plan in effect. As for the words "in all states," they refer not to *all* states that have any existing sources (as EPA proposes to read them), but rather to all states in which the WEC obligated party has equipment in a given facility. EPA itself in the proposal repeatedly notes that there are facilities which extend across state lines. *See, e.g.*, 89 Fed. Reg. at 5399. All that these words provide is that no facility is eligible for the Regulatory Compliance Exemption for existing sources until all states in which that facility is located have a state or federal existing-source plan in effect.

EPA states that its "proposed approach for implementing the Regulatory Compliance Exemption is based on a *plain reading* of the statutory text in CAA section 136(f)(6)," 89 Fed. Reg. at 5336/2 (emphasis added). However, this is patently not the case. First, EPA itself admits that it departs from a literal reading of this section when it proposes to interpret the phrase "'plans pursuant to subsection. . . (d) of section 111'" as "includ[ing] the promulgation of a Federal plan where the EPA determines that one or more states have failed to submit an approvable state plan, as that is the only way a plan pursuant to CAA section 111(d) would take effect in those states." 89 Fed. Reg. at 5337/3 (ellipsis in original). While AXPC agrees with EPA with respect to this interpretation, such interpretation is simply not a "plain reading" of the statutory text. Rather, it requires interpretation based on the structure and function of CAA Section 111, knowledge of which should be imputed to Congress as part of the background understanding of the text that it enacted here.

The entire statutory phrase at issue in Clause (i) reads:

> methane emissions standards *and plans* pursuant to subsections (b) *and* (d) of section 7411 of this title have been *approved* and are in effect in all States with respect to the applicable facilities
>
> CAA Sec. 136(f)(6)(A)(i) (emphases added).

Like EPA's interpretation that Clause (i) includes adoption of federal plans (as applicable), this provision demonstrates the need to consider the context of Clean Air Act Section 111 in interpreting these provisions. EPA does not "approve" its own federal existing-source plans, it *promulgates* them. And once the Agency has made this departure from the text's literal meaning, it loses any remaining justification for its claim that a plain reading of "in all states" requires it to wait until *all* states with *any* applicable facilities in them *anywhere* in the country have a plan in effect before affording the regulatory-compliance exemption to any facility. As with its reading of the "plans pursuant" provision, the correct interpretive approach here is to look for reasonable Congressional intent in light of the other statutory section referenced here and the nature of the regulatory problem and sector at issue.

Second, the phrase "pursuant to subsections (b) and (d) of section 7411" likewise requires a reasonable interpretation in context rather than a literal one—and here, unlike with its interpretation to include its own federal plans within the meaning of plans "approved" under Subsection (d), EPA's interpretation is not correct.

Here is EPA's interpretation:

> The EPA proposes to interpret the language in CAA section 136(f)(6)(A)(i) to mean that this temporal requirement is only met when *both* (1) emission standards for new sources under CAA section 111(b) are promulgated and in effect and (2) all state plans for existing sources pursuant to an EG issued under CAA section 111(d) have been approved by the EPA and are in effect.

89 Fed. Reg. at 5337/2. This is not the correct interpretation of the statutory text. The new-source and existing-source authority under Section 111(b) and (d), respectively, are mutually exclusive, *see Section* 111(a)(6) ("The term 'existing source' means any stationary source other than a new source."). Again, Congress was speaking at a high level in Section 136(f)(6), and again, EPA's interpretation of the Congressional intent should be informed by the text and structure of Section 111, which (f)(6) explicitly references. Because new-source regulation under 111(b) will be in effect once the recently finalized NSPS OOOOb is in effect, *i.e.*, May 7, 2024, *see* 89 Fed. Reg. at 16820/1, there is no reason for EPA to wait any longer past that date, and in particular no reason for it to wait until *any* state plan is in effect, let alone *all* state plans are in effect, before determining that new-source methane regulations are "in effect" with respect to all new sources in all states.

EPA instead should adopt the

> alternative [that] would involve a determination for methane emissions standards after the promulgation of final emissions standards for CAA section 111(b) facilities and then determinations on a state-by-state basis as each state plan containing emissions standards for CAA section 111(d) facilities were submitted and approved by the EPA (or a Federal plan was promulgated where a state did not submit an approvable plan).

89 Fed. Reg. at 5338/1. The only reason EPA gives for not adopting this approach is its belief that the statute requires "that emissions standards and plans must be approved and in effect in *all* states" before it can make the predicate determinations for the regulatory compliance exemption, but as explained above, that is not the correct reading of the statute.

g) EPA need not and should not wait until all state or federal OOOOc plans are approved or promulgated to make equivalency determinations under clause (ii)

Clause (ii) of the Regulatory Compliance Exemption requires that EPA make a demonstration that compliance with the requirements described in Clause (i) "will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 Fed. Reg. 63110 (November 15, 2021)), if such rule had been finalized and implemented." EPA proposes to conduct the analysis for purposes of this equivalency determination at a national level, comparing the national-level emissions reductions that would have been achieved under the NSPS OOOOb/EG OOOOc 2021 Proposal (if finalized as proposed) against those that will be achieved upon implementation of the final NSPS OOOOb/EG OOOOc. Further, EPA proposes that the two determinations (1) federal regulation equivalency and (2) state plan equivalency be made together, at one time, for NSPS OOOOb and all state and federal OOOOc plans.

EPA's proposal that it make both determinations at once is based on their interpretation that the language of the statute calls for "one single determination." However, as discussed throughout, this interpretation is not in line with principles of statutory construction, or the purpose of the statute. The full sentence reads that plans are "approved and are in effect in all States with respect to the applicable facilities" and as discussed elsewhere, should not be read to refer to all applicable facilities nationwide. Additionally, EPA states that the determination cannot be made until standards and plans are in place in all states because the equivalency determination must be made on a nationwide scale.

We do not agree that EPA must make this determination after all plans are approved and in effect. EPA's focus on "a" determination is very unpersuasive. Furthermore, the singular use of "a" within the phrase "upon a determination by the Administrator" is countered by the singular word "an" within the phrase "[c]harges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements." This phrase clearly contemplates that the Regulatory Compliance Exemption is being made for particular applicable facilities, and *that* is the correct frame through which the subsequent phrase "a determination" should be made.

EPA's interpretation would put operators in States with timely plans at the mercy of other States. This would essentially eliminate the exemption for the first several years. A two-step analysis, that first determines equivalency of NSPS OOOOb, and then determines equivalency of NSPS OOOOc and state plans, will eliminate wasted time and resources because if NSPS OOOOb does not meet the equivalency determination, then neither will NSPS OOOOc.

EPA in fact has all the information it needs to make the equivalency determination *now*, and that determination is ripe for the making now (or at latest when the March 2024 final rule takes effect in May 2024). In the November 2021 proposal, EPA made certain projections as to the emissions reductions it projected would result from implementation of the proposal, and in the March 2024 final rule, EPA issued updated versions of the projections. Its March 2024 projections *exceed* the November 2021 projections (even adjusting for the longer time frame for which the final rule makes these projections), *compare* 86 Fed. Reg. at 63257/3 (Nov. 2021 proposal) *with* 89 Fed. Reg. at 17017/2-3 (Mar. 2024 final rule), demonstrating that compliance with the final rule will meet the standard articulated at CAA Sec. 136(f)(6)(A)(ii).

EPA therefore can and should make the equivalency determination now. However, even if EPA rejects this approach, at the very least, a state-by-state approach is more aligned with Congress's intent than EPA's proposed approach, because it will ensure efficiency in the process and ensure more operators are eligible for the exemption. The state determination can be done in parallel with the evaluation and approval of each state's plan (or in parallel with EPA's promulgation of a federal plan for a state's existing sources). Under this approach, once a state plan is approved (or a federal plan is promulgated), the EPA can also make a determination of equivalency. Further, the approach is simplified if EPA has already determined that NSPS OOOOb is equivalent, because then the state plan's approval means it meets the requirements of 111b and 111d, and thus it is equivalent.

CAA Sec. 136(f)(6)(A)(ii) provides that the Regulatory Compliance Exemption requires a determination by the Administrator that the regulatory requirements referenced in (A)(i) "will result in equivalent or greater emissions reductions as would be achieved by the [November 2021 proposal], if such rule had been finalized *and implemented*." (Emphasis added.) The "implementat[ion]" of existing-source regulation pursuant to both Section 111(d)(1) (state plans) and (d)(2) (federal plans) entails the states' prerogative (under (d)(1) to "take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies," and EPA's own *obligation* (under (d)(2)) to "take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies." (This language is what EPA refers to by the acronym RULOF, for "remaining useful life and other factors.").

In other words, RULOF considerations *are part of* existing-source rule implementation, as the text and structure of Section 111(d) clearly demonstrate, and Congress was aware of this fact when it enacted the Regulatory Compliance Exemption provision at Section 136(f)(6). EPA is therefore wrong to suggest, *see* 89 Fed. Reg. at 5342, that the statutory RULOF authority somehow prevents it from making an equivalency determination with respect to existing-source plans until those plans are approved (for state plans) or promulgated (for federal plans). RULOF considerations would have been available to states (and mandatory for EPA) under Section 111(d) "if [the November 2021 proposal had been finalized and implemented" in the same manner as those considerations are available to states (and mandatory for EPA) now that the March 2024 final rule has been finalized and will be implemented. Congress's contemplation of the finalization and implementation of the November 2021 proposal necessarily entails exercise of the statutorily available RULOF authority. Therefore, questions of RULOF are no barrier to EPA making its equivalency determination now.

h) AXPC agrees with EPA on certain conclusions

AXPC agrees with EPA's interpretation that the Regulatory Compliance Exemption should be available when state or federal plans are in effect (see elsewhere for disagreement that all state or federal plans need to be adopted) even if full implementation of those requirements is not required until a future date.

AXPC further agrees with EPA's interpretation that operators are eligible for the exemption for the entire calendar year during which the requisite determinations that the regulatory exemption is available occur (for example, if June 2027, then the whole of 2027). This should not be for a portion of the reporting year or for the next reporting year. It should be noted that the typical calendar-year cadence described in the proposed rules for Subpart W/WEC filings may be out of step with OOOOb as the first compliance reporting is currently expected to be in July or August.

VI. Definitions should reference 40 CFR 98 Subpart W

EPA had defined some terms the same and some terms differently from 40 CFR 98 Subpart W. To avoid conflicting definitions and having to update definitions in two places, EPA should instead simply reference the definitions in 40 CFR 98 Subpart W.

VII. EPA should not require the operator to pay for audits

EPA should not require the operator to pay for a third-party audit of the WEC. EPA should conduct the audit or pay for the auditors. EPA's proposal in this regard presents the daunting prospect of unknown costs on operators.

VIII. EPA should exclude stationary fuel combustion emissions reported under Subpart W that could otherwise be reported under Subpart C

The proposed WEC rule arbitrarily treats stationary fuel combustion emissions differently depending on whether those emissions occur at a facility reporting under Subpart W or at a facility in an industrial segment such as gas processing or transmission that reports the same type of combustion emissions under Subpart C. This inconsistency arises not from any technical difference or legal reason but merely from how EPA has defined "WEC applicable facility" to include all emissions reported under Subpart W, without accounting for the arbitrariness of including stationary fuel combustion emissions that must be reported under Subpart W due to the type of oil and gas facility. Inclusion of fuel combustion emissions in the WEC facility emissions is inappropriate because methane emissions from fuel combustion are not waste. Emissions from fuel combustion (e.g., engines) occur through routing of natural gas to fuel combustion equipment (such as engines) for beneficial use. To correct these concerns, EPA should exclude stationary fuel combustion unit emissions that are reported under § 98.232 pursuant to § 98.232(k) (these could be defined as those that could otherwise be reported under Subpart C), from counting towards the waste emission charge.

The intent of the WEC is to encourage the reduction of methane emissions and this was effectuated in part by tying the WEC to compliance with OOOOb and OOOOc requirements.[8] EPA acknowledges this in the proposal, saying "The EPA expects that, as oil and gas operations implement the requirements of final NSPS OOOOb and the plans issued and approved pursuant to EG OOOOc (and undertake other methane mitigation voluntarily or due to other Federal or state regulations), total reported Subpart W facility methane emissions would decline."[9] It follows that Congress did not intend to subject an upstream operator to WEC obligations resulting from stationary fuel combustion emissions, when these emissions are separate and unrelated from the issue of whether a facility's methane emissions associated have been reduced as much as practicable pursuant to NSPS OOOOb or OOOOc requirements. Further, as noted above, these emissions are not waste emissions. Excluding upstream operators' stationary fuel combustion emissions that could otherwise be reported under Subpart C from the WEC facility emissions calculation is congruent with the intent of the WEC to incentivize the reduction of methane emissions in accordance with NSPS OOOOb and OOOOc.

Therefore, in the final rule, EPA should exclude stationary fuel combustion emissions reported under Subpart W that could otherwise be reported under Subpart C from the calculation of whether the facility owes a WEC obligation.

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[8] See 42 U.S.C. § 7436(f)(6)(A) (relating to the exemption for "compliance with methane emissions requirements. . . standards and plans").

[9] 89 Fed. Reg 5318 at 5345 (Jan. 26, 2024).

INDEPENDENT PETROLEUM
ASSOCIATION OF AMERICA

March 26, 2024

U.S. Environmental Protection Agency
EPA Docket Center
Air and Radiation Docket
Mail Code 28221T
1200 Pennsylvania Avenue NW,
Washington, DC 20460.

Docket Number: EPA–HQ–OAR–2023–0434
Waste Emissions Charge for Petroleum and Natural Gas Systems

The Independent Petroleum Association of America (IPAA) submits these comments regarding the Environmental Protection Agency (EPA) proposal to implement a Waste Emissions Charge for Petroleum and Natural Gas Systems (WEC) under the Inflation Reduction Act Methane Emissions Reduction Program (Methane Tax).

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of American oil and natural gas wells, produce 83 percent of American oil and produce 90 percent of American natural gas.

In addition to the comments filed here, unless there are specific comments presented herein, IPAA endorses the comments filed by the American Petroleum Institute (API).

The Methane Tax process includes multiple features. However, a key factor in conjunction with this WEC proposal is the application of information from Subpart W. IPAA previously filed comments on the EPA proposal to modify Subpart W (EPA-HQ-OAR-2023-0234-0265). These comments are included in this submission as Appendix A.

Because the emissions calculations under Subpart W are the building blocks for calculation of the WEC, these comments will reiterate and expand on those prior comments. Then, it will address key issues in the WEC proposal.

A. Subpart W

There are several key issues within EPA's Subpart W proposal that remain unresolved and yet essential to the consideration of the WEC proposal because they define the emissions amounts that will ultimately be taxed. One of these is a fundamental issue related to the definition of a facility under the Methane Tax as it relies on Subpart W. A second issue relates to EPA's failure to properly assess emissions factors that become the emissions basis. These will be addressed below.

1. *EPA fails to properly develop a facility definition for the Methane Tax that is consistent with the Clean Air Act.*

The issue of the Subpart W facility definition is not a new one, but it has returned to focus because of EPA's choice to use it without addressing whether it is appropriate for the Methane Tax. The underlying structure of the Subpart W facility definition has been contentious since it was first proposed and adopted for the Greenhouse Gas Reporting Program (GHGRP). The principal issue continues to be that the definition fails to reflect the realities of oil and natural gas production operations. It fails to track other definitions of oil and natural gas production facilities in the Clean Air Act (CAA). EPA's default to the use of the Subpart W definition in the GHGRP context is inappropriate and not required by the Methane Tax.

IPAA has consistently recommended that EPA more properly define Subpart W facilities in the context of the general understanding of facilities within the CAA and the industry. In 2010 comments filed when the facility definition was first developed, IPAA stated the following:

> Most notably, we believe that use of the CAA denies EPA the authority to create a definition of a facility that differs from that in the CAA. EPA proposes the following definition:
>
> > Onshore petroleum and natural gas production facility means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.
>
> Under this definition, for example, all wells under common ownership along the Gulf Coast of Texas and Louisiana and deeply into the mainland of those states would be considered as one facility. This would be analogous to proposing that every McDonalds restaurant in the State of Texas should be considered as one facility because they have the same name and are franchised from a common source.
>
> Nothing in the CAA suggests that EPA can define an onshore petroleum and natural gas production facility as broadly as it proposes. In reality, the only guidance provided to EPA in the CAA resides in Section 112(n)(4)(A) where it states:
>
> > … in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose ….
>
> EPA proposes its basin approach and solicits comment on the option of using a similar approach involving "field-level reporting". In doing so, the Agency discounts the obvious choice – the well pad. Clearly, the well pad looks like a facility under the definition in the CAA and is the typical permitting unit under CAA regulations. EPA considered a well pad approach and "EPA analyzed the average emissions associated with each of the four well pad facility cases and determined that average emissions at these operations were low (from about 370 metric tons of CO2e per year to slightly less than 5,000 metric tons of CO2e per

year).” Recognizing that individual sources were small, EPA chose to create its novel basin approach.

We identified this issue in our comments to EPA’s proposal in 2009 when we stated:

> We believe that including onshore petroleum and natural gas production facilities in the reporting requirements runs counter to EPA’s focus in this proposal. EPA structured the proposal by selecting its 25,000 tons/year facility reporting threshold in part based on a cost effectiveness test to capture most of the GHG emissions while limiting excessive costs. Despite this effort, under the current proposal 43 percent of the first year capital costs to comply with the rule will be borne by the petroleum and natural gas industry to report an estimated 3 percent of the nation’s GHG emissions. Expanding the reporting requirements to onshore facilities will dramatically increase these costs unnecessarily.
>
> American petroleum and natural gas production comes from approximately 933,000 wells – roughly 500,000 oil wells and 433,000 natural gas wells. These facilities are spread across 33 states. Offshore facilities would be within the scope of the reporting requirements. EPA estimates that 50 offshore facilities would be covered under the 25,000 tons/year threshold. If EPA were to expand the reporting requirements to onshore facilities, it is highly unlikely that any production well facility would meet the reporting threshold. For example, approximately 85 percent of oil wells and 74 percent of natural gas wells are marginal wells producing less than 15 barrels/day of oil and 90 mcf/day of natural gas, respectively. Most of these operations are owned by small businesses. None of them would exceed the reporting threshold individually.
>
> EPA largely seems to recognize this reality when it states:
>
> > …this segment is not proposed for inclusion primarily due to the unique difficulty in defining a ‘‘facility’’ in this sector and correspondingly determining who would be responsible for reporting.
>
> EPA has requested comments on how to define a facility for onshore petroleum and natural gas production and whether to require reporting on a basin level. We believe that the appropriate facility definition tracks the nature of the operation – essentially a well pad which may contain one or several wells and the attendant separation and storage facilities. As we discussed above, these operations will fall well below the reporting threshold. To approach the reporting on a basin level would result in compelling this industry to use a reporting threshold far below the 25,000

> tons/year threshold required for other industries. In essence, all production operations would have to determine emissions levels by whatever estimation or monitoring requirements would apply. This would impose dramatically different costs. To put all of this in some perspective, EPA's INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990- 2007 (Released on April 15, 2009) would suggest that the GHG emissions from natural gas systems and petroleum systems account for roughly 2.3 percent of U.S. GHG emissions. EPA suggests that about 27 percent of these emissions come from onshore petroleum and natural gas production operations – or roughly 0.6 percent of U.S. GHG emissions.
>
> There is no compelling rationale to justify imposing on this segment of American industry a far costlier reporting requirement, capturing hundreds of thousands of wells many owned by small businesses, solely for the purpose of minimally improving the U.S. GHG emission inventory.

This circumstance has not changed appreciably. EPA argues that it has underestimated the amount of GHG emissions from onshore petroleum and natural gas production systems. The 2008 U.S. Inventory of Greenhouse Gases reported 131 MMTCO2e from petroleum and natural gas systems. EPA believes the emissions are 351 MMTCO2e. To put this in the same perspective as our 2009 comments, these systems would account for slightly more than 6 percent of U.S. GHG emissions and the onshore petroleum and natural gas production systems would be approximately 3.9 percent. EPA must recognize the burden it will impose on the small businesses that operate the majority of these systems.

Small Business Implications

EPA cavalierly asserts that this proposal "…will not have a significant economic impact on a substantial number of small entities." But, can this be true? Comparing numbers of wells that must report against the number of wells operated by small businesses shows a different result.

In creating its basin-level reporting approach, EPA indicates that it will capture 81 percent of the onshore petroleum and natural gas production GHG emissions. It also states – in rejecting the logical well pad facility definition – that individual well pad emissions were low. Consequently, we must conclude that EPA's definition must capture something close to 80 percent of the operating wells.

In 2008, there were 960,303 operating wells in the U.S. (525,287 oil wells and 435,016 natural gas wells, with about 7,000 of these in the federal offshore). The Energy Information Administration reports that 85 percent of these oil wells and 73.3 percent of these natural gas wells are marginal wells. Assuming a proportional distribution across wells, the following results would be produced:

	Wells Reported Under Rule	Marginal Wells Reported Under Rule
Oil Wells	417,300	354,815
Natural Gas Wells	345,213	253,041
Total	762,513	607,856

> Clearly, there will be a pervasive burden borne by America's marginal well producers. EPA is well aware that the companies operating marginal wells are dominated by small businesses. To suggest that the proposed rule will not have a significant impact on small businesses is simply incorrect.

EPA rejected these arguments with the following rationale in its publication of the GHGRP Subpart W regulations:

> We are also including two distinctive definitions of facility for onshore petroleum and natural gas production and for natural gas distribution. Defining a facility in these cases is not as straightforward as other industry segments covered under subpart W. For some segments of the industry (e.g., onshore natural gas processing, onshore natural gas transmission compression, and offshore petroleum and natural gas production), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying the scope of reporting and responsible reporting entities. However, in onshore petroleum and natural gas production and natural gas distribution such distinctions are more challenging. As explained in the April 2010 proposal, EPA evaluated existing definitions used under current regulations and determined that it was necessary to provide a unique definition of facility for each of these two segments in order to ensure that the reporting delineation is clear, avoid double counting, and ensure appropriate emissions coverage. For more information please see the preamble for the April 2010 proposal (75 FR 18608) and the Greenhouse Gas Emissions from Petroleum and Natural Gas Industry: Background Technical Support Document (EPA–HQ–OAR–2009–0923).
>
> These definitions are intended only for purposes of subpart W and are not intended to affect to definition of a facility as it might be applied in any other context of the Clean Air Act.

This commitment will no longer be true if EPA applies the Subpart W facility definition in the Methane Tax.

There is nothing in the CAA nor in the Methane Tax that justifies EPA transferring the facility definition component of Subpart W to the Methane Tax. Rather, it is more pertinent to look to other agency actions addressing the definition of oil and natural gas production facilities.

The general concept of a "facility" under the CAA revolves around a typical plant site composed of a single operation or multiple interlocking operations like a refinery or chemical plant or steel mill. Certainly, the dispersed historical nature of oil and natural gas production facilities has made defining those facilities more difficult. However, the only place in the CAA where Congress has spoken is under Section 112 where the language states:

> ...emissions from any oil or gas exploration or production well (with associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.

Where EPA is so frequently referring to the plain reading of the language of the Methane Tax in this proposal, this Congressional directive should bear strongly on EPA's interpretation.

Supporting the concept of using a tightly drawn definition of a facility is EPA's actions in defining a "major source" under its federal operating permit requirements as follows:

> *Major source* means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining "major source," a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (*i.e.,* all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987. For onshore activities belonging to Standard Industrial Classification (SIC) Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1/4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment. Shared equipment includes, but is not limited to, produced fluids storage tanks, phase separators, natural gas dehydrators or emissions control devices.

This interpretation was developed through an extensive rulemaking and did not come quickly. Yet, it, too, provides evidence that EPA can come to a rational decision on defining an oil and natural gas production facility. Significantly, this action occurred in 2016, well after the Subpart W facility definition was created.

EPA now faces a different more compelling situation than it did in 2010 when it drafted Subpart W. Congress not only created the Methane Tax, it also intended that the tax should not apply to small well producers. As Senator Manchin stated in his June 2023 letter to EPA:

> - The statute clearly intends to exempt marginal wells and smaller producers from the fee.[3] EPA must make it clearly understood that those entities not subject to the current Subpart W Greenhouse Gas Reporting Program are not subject to EPA fees under MERP.
> - ...
> - EPA should draw reasonable boundaries around the definition of individual "facilities" (such as pad site, compressor site, or reporting field) for emissions intensity calculations so that aggregations of large amounts of disparate wells

and gathering lines does not lead to charging a fee on marginal facilities that Congress intended to exempt or on facilities that have minimal actual emissions.

EPA's use of the facility definition from Subpart W thwarts both these mandates. EPA's sweeping scope of a facility using the American Association of Petroleum Geologists (AAPG) basins to define a facility compels small producers to aggregate all their small producing wells over huge areas, like the entire state for West Virginia or Michigan.

To give some perspective to the potential impact of the use of the sweeping facility definition under Subpart W, a few facts can provide some insight. First, it's important to understand that small business oil and natural gas producers typically need to operate hundreds of small wells across an AAPG basin to be economic. Second, looking at the most recent GHGI (providing data on 2022 emissions), it shows that the distribution of CO_2eq emissions for natural gas production wells is approximately 9 percent CO_2 and 91 percent methane (as CO_2eq). For petroleum (oil) wells the distribution is approximately 33 percent CO_2 and 67 percent methane (as CO_2eq). Third, the following table shows how these distributions result in emissions to make up the 25,000 tonnes/year threshold in the Methane Tax.

Emissions Producing 25,000 tonnes/year				
CO_2 Emissions	Methane Emissions (CO_2eq)	Methane Emissions (21 GWP)	Methane Emissions (25 GWP)	Methane Emissions (28 GWP)
Natural Gas Production (tonnes/year)				
2187	22813	1086	913	815
Oil Production (tonnes/year)				
8188	16812	801	672	600

This table shows the mass of methane emissions based on three methane Global Warming Potentials (GWP) -- 21 (2010 GWP), 25 (the current GWP) and 28 (EPA's proposed revision to the GWP). In this discussion, it is assumed that EPA will finalize its proposed GWP revision and change the methane GWP to 28. Fourth, when EPA proposed its Subpart OOOOb and OOOOc regulations in 2021, it set a threshold for its Leak Detection and Repair (LDAR) program of 3 tons/year (2.722 tonnes/year) from a well site. This can be considered as a proxy for a marginal well.

Using this information, a small business well producer with operations across an AAPG basis would be subject to the Methane Tax threshold with as few as 220 oil wells or 300 natural gas wells. These totals are well within the operations of a typical small producer. Clearly, this application violates the Congressional intent to exclude small businesses and marginal wells from the scope of the Methane Tax.

2. *EPA's proposed approach to a WEC applicable facility egregiously worsens the impact on small producers that own Gathering and Boosting operations*

As adverse as the Subpart W facility definition is for small producers, EPA would make it extraordinarily harsher if the producer operates Gathering and Boosting. First, the Gathering and Boosting (G&B) Emissions Factors (EF) under Subpart W for methane emissions are based on mileage of pipe, not on actual emissions. Second, the WEC emissions threshold for G&B is one quarter of the threshold for natural gas production. Third, EPA is proposing that production (oil and natural gas) and G&B be treated as one applicable facility under the Methane Tax. Under this approach, which will be discussed in more detail below, using the EF in EPA's proposed Subpart W revisions, a small producer with as little as 560 miles of unprotected pipe in an AAPG region would equate to the 300 marginal natural gas wells described above and thereby pull that producer into the Methane Tax.

3. *EPA fails to properly address the accuracy of the emissions factors it was mandated to improve under the Methane Tax.*

As stated above, IPAA has previously addressed its concerns about EPA's actions to fulfill its mandate under the Methane Tax to revise Subpart W. While those comments present a more extensive view, a key aspect is restated here:

> EPA actions to revise component emissions factors raise serious questions about both the approach and the proposal. As discussed above, the Inflation Reduction Act mandate to revise Subpart W requires EPA to conduct thorough analyses of the numerous emissions factors and either independently validate them or develop its own valid factors. It failed to do either.
>
> Instead, it turned to three reports as the basis for new emissions factors. These reports are generally referenced as Zimmerle[1], Pacsi[2] and Rutherford[3].
>
> However, EPA's use of these materials demonstrates a callous disregard for the mandate EPA must meet in revising Subpart W. The Zimmerle report addresses emissions from gathering compressor stations; the Pacsi report addresses emissions from oil and natural gas production equipment leaks. Each of these studies conclude that the current emissions factor calculation process under Subpart W overstates emissions that they studied. The Zimmerle report states:
>
>> Combining study emission data with 2017 GHGRP activity data, the study indicated statistically lower national emissions of … 66% … of current GHGI estimates, despite estimating 17% … more stations than the 2017 GHGI ….
>
> The Pacsi report states:
>
>> The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22% to 36% for the sites surveyed in this study as compared to direct measurements of leaking components because of a lower frequency of leaking components in this work than during the field

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[1] Zimmerle, D., et al. "Methane Emissions from Gathering Compressor stations in the U.S." Environmental Science & Technology 2020, 54(12), 7552-7561, available at https://doi.org/10.1021/acs.est.0c00516.

[2] Pacsi, A. P., et al. "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." Elem Sci Anth, 7: 29, available at https://doi.org/10.1525/elementa.368. 2019

[3] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. et al. Closing the methane gap in US oil and natural gas production inventories. Nat Commun 12, 4715 (2021). https://doi.org/10.1038/s41467-021-25017-4

> surveys conducted more than 20 years ago to develop the current EPA factors.

To show the EPA lack of regard for its mandate, EPA ignores these conclusions and cherry picks elements of the reports to increase the component emissions factors in Subpart W. The Rutherford study takes a different approach. It makes the assumption that component based emissions estimates understate actual emissions because it believes that ambient monitoring presents more accurate results. Consequently, it surveys a variety of component based emissions studies to create emissions factors higher than those in the current Subpart W and adopts them as more accurate.

Critically, EPA embraces all these various changes that increase the Subpart W emissions factors, but it never attempts to independently validate them. The effect of this action is increases in virtually every component emissions factor, some of which would yield emissions estimates 5 times or more than the current Subpart W calculations. Not only is this approach a clear dereliction of EPA's responsibilities, but it also has the effect (along with changing the GWP for methane) of de facto lowering the 25,000 mt/year threshold and raising the emissions subject to methane tax. Enverus Intelligence Research, a subsidiary of the energy-focused Software as a Service firm Enverus, has found the proposed regulations would more than double 2021 reported methane and increase overall carbon dioxide-equivalent emissions by 41%. If EPA is intentionally revising the Congressionally enacted methane tax through its rulemaking actions, it should be held to a standard that requires it prove that its revisions are valid.

B. Waste Emissions Charge

Because the Methane Tax contains no legislative history and frequently fails to truly define its terms, EPA must interpret the legislative text. In its proposal EPA frequently refers to terms like "a plain reading" of the statute. However, EPA manipulates its reading of the text by only partially reading the text or ignoring key terms. As a result, it creates inappropriate conclusions and therefore inappropriate regulatory proposals.

Definition of Applicable Facility

As described previously, EPA fails to address the inappropriate use of the GHGRP Subpart W facility definition in the Methane Tax – a definition that EPA characterized by describing as follows:

> These definitions are intended only for purposes of subpart W and are not intended to affect to definition of a facility as it might be applied in any other context of the Clean Air Act.

But, in the definition of "applicable facility", EPA proposes a definition that compounds this misuse outrageously. EPA proposes that:

> In cases where a subpart W facility reports under two or more of the industry segments listed in the previous paragraph, the EPA proposes that the 25,000 mt CO2e threshold would be evaluated based on the total facility GHG emissions

reported to subpart W across all of the industry segments (i.e., the facility's total subpart W GHGs).

This proposal appears to create a structure that would compel operators to sum emissions of their operations in an AAPG basin to include, for example, their oil and natural gas production operations and their G&B operations such that if both were below 25,000 mt/year but the sum were above 25,000 mt/year, their operations would then become subject to the WEC. This proposal extends an already inappropriate approach to a facility definition to arbitrarily capture even more operations for what is solely intended to make them subject to the Methane Tax. It should be summarily rejected.

Calculations of WEC Emissions Thresholds

1. *EPA fails to use natural gas when the term is in the text of the statute.*

A key and clear failure in EPA's interpretation of the legislative text is its failure to use natural gas as the basis of WEC thresholds when the term is in the text. This failure results in EPA effectively raising the WEC emissions threshold by about 30 percent. Most of the WEC emissions thresholds are based on natural gas sales or throughput. This discussion will focus on the emissions threshold for the onshore petroleum and natural gas production industry segment that sends natural gas to sales. EPA presents this calculation as follows:

$$TH_{is,Prod} = 0.002 \times \rho_{CH4} \times Q_{ng,Prod} \qquad \text{(Eq. B-1)}$$

Where:

$TH_{is,Prod}$ = The methane waste emissions threshold for the industry segment at a WEC applicable facility for the reporting year in the production sector that has natural gas sent to sale, metric tons (mt) CH_4.

0.002 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for methane emissions for applicable facilities with natural gas sales in the production sector, thousand standard cubic feet (Mscf) CH_4 per Mscf of natural gas sent to sale.

ρ_{CH4} = Density of methane = 0.0192 kilograms per standard cubic foot (kg/scf) = 0.0192 metric tons per thousand standard cubic feet (mt/Mscf).

$Q_{ng,Prod}$ = The total quantity of natural gas that is sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to part 98, subpart W of this chapter. For onshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(1)(i)(B) of this chapter, in Mscf. For offshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(2)(i) of this chapter, in Mscf.

The two key factors in this equation are the use of natural gas sales as the basis of the emissions threshold and the use of methane density to convert volume to mass. Methane is not natural gas.

Natural gas is denser than methane. By using methane density instead of natural gas density, EPA lowers the emissions threshold and effectively raises the Methane Tax payment.

Then, in one of its more disingenuous statements, EPA argues that its use of methane density instead of natural gas density is actually intended to decrease the reporting burden on industry.

> With the exception of production facilities that only produce oil, the statutory text clearly lists natural gas as the throughput value. Further, the proposed approach can be implemented with data currently reported under subpart W, while alternative methane intensity methodologies would require reporting of additional data and increase the burden on the oil and gas industry. ... An approach that calculates methane intensity as the mass of methane emissions divided by the mass of natural gas would require facilities to collect and report detailed information on all of the constituents of natural gas throughput. ... The EPA therefore believes that the proposed approaches not only follow a plain reading of CAA section 136(f) but are also the best and most reasonable approaches.

If EPA really believes in plainly reading the statute, it will clearly conclude that the statute uses natural gas as the basis for the WEC and the emissions threshold. Consequently, its task is to present options to use natural gas density in its calculations.

Certainly, one option should be for operators to provide natural gas density information based on their operations and EPA needs to provide a framework for the submission of such data.

However, other approaches are also available. For example, since 2011, EPA has used a memorandum, "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking" (included as Appendix B in this document) to provide natural gas composition data for its regulations. Using this document, a natural gas density of approximately 0.0535 lb/scf can be calculated. This demonstrates the significance of using a natural gas density rather than the methane density of 0.0416 lb/scf. It is nearly 30 percent higher. Given that EPA has been using this document for its rulemaking for over a decade, it can certainly be used as a default value if no other information is available.

Another approach that EPA could take would be to work with organizations like the Energy Information Administration or the Gas Technology Institute or Enverus that may have databases with AAPG basin average natural gas densities. If such databases do not exist, EPA could initiate an effort by one of these organizations to obtain such information. These densities could then be used as AAPG basin default values when no other information is available.

Any approach to define default natural gas densities and to provide for operator supplied natural gas densities are clearly plausible approaches to address the issue of needing a natural gas density to calculate the emissions threshold.

But what is clear is that EPA's approach of using a methane density is not a valid plain reading of the statute and must be altered.

2. *The current approach is unfair to oil dominated production and must be changed.*

Some of the emissions thresholds in the Methane Tax seem to be derived from various voluntary emissions intensity programs related to natural gas production. At least this appears to be the case for the onshore production emissions threshold for operators with natural gas sales. This emissions intensity target was developed by companies operating production that is dominated by natural gas sales. While it may be a rational target for such operations, it is inappropriate for production that is primarily petroleum with minimal or limited natural gas sales. Similarly, the emissions threshold for petroleum production with no natural gas sales is wholly inconsistent with the threshold for natural gas production facilities and generates a likely impossible target to meet.

The following are some examples of the implications of the emissions thresholds for different operations. For illustrative purposes, they will be based on petroleum production of one million barrels/year. One million barrels per year can be converted to natural gas production based on energy equivalency which is 6 mcf of natural gas is equivalent to one barrel of oil. Therefore, one million barrels of oil is equivalent to 6 million mcf of natural gas.

For petroleum production with no gas sales, the Methane Tax emissions threshold is 10 metric tons per one million barrels. If this production was natural gas where the emissions threshold is 0.2 percent of natural gas sales, then for 6 million mcf of production (using natural gas density in the calculation), the threshold would be 292 metric tons. This multiple of 29 is wholly inappropriate.

A similar issue exists for a petroleum producer with limited natural gas sales. Assume that the same petroleum producer had an additional one percent of its oil production as natural gas – 60,000 mcf. This would produce a natural gas emissions threshold of about 2.9 mt. Again, a threshold that is wholly inconsistent with a comparable natural gas energy producer.

3. *The G&B emissions threshold has no identifiable basis and is inequitable*

There is nothing in the Methane Tax that explains why the emissions threshold for G&B was selected. It is well below the emissions threshold for other segments of the industry. This low threshold is complicated by the egregious use of the Subpart W EF for G&B. As noted above, the G&B EF are based on miles of pipe and do not reflect control measures or emissions data that could show dramatically different emissions profiles. EPA needs to justify the G&B emissions threshold and generate valid EF for this sector.

Compliance Date for the Submission of Methane Tax Payments

EPA's proposed approach for the payments of the Methane Tax is unjustified and flies in the face of historic filing issues with the GHGRP. For the many years that the GHGRP has been in operation, the filing date has been March 31 of the year following the year of emissions reporting (e.g., March 2024 for 2023 data). However, given the short time frame to develop the data, verification of data has extended into November in many instances.

Now, EPA is proposing that the WEC filing and payment must be submitted on March 31. It allows modifications to the WEC filing to be made until November 1. However, while any reductions in emissions would allow for a rebate, increases would have penalties applied to them. This approach is unnecessary. Given the history of the GHGRP, EPA knows there will likely be modifications needed for many filings. Consequently, a fair approach would delay the payment date until November 1, after the revisions and verifications have been completed.

Regulatory Compliance Exemption

IPAA has doubted that the Regulatory Compliance Exemption (Exemption) would be realistically available; it has always appeared a false promise. Consistent with this perception, EPA's proposal demonstrates that it will use every measure possible to prevent the application of the Exemption.

1. *The Exemption Proposal is Inconsistent with the Plain Reading of the Statute*

To begin with, EPA shows its bias by choosing to cleverly try to parse the language of the statute and make it as unworkable as it can. Its first act is to misread the following language:

> ...methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities.

EPA chooses to focus on the term "all States" in isolation from the reference to "applicable facilities". A clear plain reading of the statute would reflect Congress' already punitive limitation on companies that would prevent them from using the Exemption as soon as a state in which they operate has plans in place by requiring that all the states where they had applicable facilities have approved section 111(b) and section 111(d) plans in place. That is, if a company had applicable facilities in Texas and West Virginia, it could not benefit from the Exemption in Texas if West Virginia's plans had not been approved. Both Texas and West Virginia must have approved plans.

EPA drives the issue to an absurd conclusion by interpreting the language to mean that if a company had operations in Texas and West Virginia and both had approved plans, the company could not utilize the Exemption if, say, South Dakota did not have approved plans – a state where it had no applicable facilities.

EPA's rationale for this interpretation can have no purpose other than to prevent the Exemption from being used and compel higher taxes on companies when they are, if fact, acting as the statute would envision – reducing their methane emissions and complying with the regulations.

2. *The Equivalency Proposal is Unfair and Designed to Prevent Use of the Exemption*

The second major task for EPA involving the Exemption relates to determining whether the promulgated Subpart OOOOb regulations and the forthcoming Subpart OOOOc state regulations "will result in equivalent or greater emissions reductions as would be achieved by the [2021] proposed rule…". EPA's course of action here is to punt. EPA merely states it will address this action in a future rulemaking after all the state plans have been approved.

This deferral of action by EPA leaves the entire process in an unacceptable limbo. This decision has always been fraught with confusion and EPA does nothing to create a framework for industry or states as it avoids any action – even when some actions are possible.

At issue here is that not only will this determination affect the Methane Tax, it can influence the state planning process if EPA were to conclude that the Subpart OOOOb regulations failed to meet the equivalency test. If so, it would mean that state plans would have to fill the gap perhaps compelling existing source regulations that are more extreme than those in the EG – or Subpart OOOOb.

Confounding the decision-making process is the fundamental challenge inherent in interpreting the 2021 Subparts OOOOb and OOOOc proposals. The 2021 proposal was largely devoid of true regulatory language, raising the issue of how EPA will evaluate this amorphous proposal. Numerous questions arise. For example:

a. How will EPA interpret the 2021 Subpart OOOOb proposal against the final 2024 Subpart OOOOb regulations? This comparison can be made now since the Subpart OOOOb regulations are final.
b. How will EPA address the 2021 Subpart OOOOc proposal given that the EG process allows states to develop comparable regulations and that the Remaining Useful Life and Other Factors (RULOF) provisions of Section 111(d) can be applied and applied differently in each state? Understanding this framework could potentially significantly affect EPA's conclusion.

EPA's failure to suggest how it will grapple with these complex decisions leaves the regulated community and states in a position of trying to make key regulatory and investment decisions in a void. Also, EPA's failure to address these decisions allows it to prevent applicable facilities from accessing the Exemption by not taking any action. Under the deferral approach, all state plans could be approved, but EPA could just defer the Exemption by making no decision.

There is nothing in the statute that prevents EPA from making segmented determinations on the equivalency of regulatory programs relative to the 2021 proposal. For example, as suggested above, EPA could determine if the final Subpart OOOOb regulations are equivalent to the 2021 Subpart OOOOb proposal. If they are not, it largely closes out the availability of the Exemption. Similarly, state-by-state determinations regarding Subpart OOOOc are feasible with the larger question being how EPA will assess how the 2021 Subpart OOOOc EG would have been implemented when there is virtually no regulatory language available. At least under a state-by-state approach, the potential for the Exemption to be available in a timely manner would be far higher, particularly if EPA junks the current proposal that all states must have approved plans before any applicable facility can utilize the Exemption and returns to a more logical plain reading of the statute that is described above.

EPA's approach in comparing the 2021 proposal to the 2024 final Subpart OOOOc EG would be inappropriate and unfair to the most vulnerable of existing sources. EPA asserts that it would assume that the 2021 EG would be implemented as proposed (although the proposal was not regulatory language). However, it would compare that assessment with the approved state plan that includes RULOF facilities. Such an approach is inequitable. First, there is no reason to assume that the RULOF facilities under the 2024 EG would not have been RULOF facilities under the 2021 proposal since they are clearly facilities where the regulations pose such a severe burden that they qualify as RULOF facilities. Second, penalizing all applicable facilities in a state because it has RULOF facilities is completely unwarranted and inequitable. Third, if the impact of the approach is to deny facilities that deserve RULOF treatment its application in order to obtain the Exemption for the remaining facilities in a state is an egregiously harsh punishment for those uneconomic facilities that are likely mature operations and probably small businesses. Therefore, a more equitable approach would compare whatever EPA concludes in the efficacy of the 2021 EG proposal with the basic regulatory structure in an approved state plan under the 2024 EG.

3. *Actual Noncompliance Needs to be the Basis for Denying an Exemption*

The third key ingredient to obtaining the Exemption is compliance with the Subpart OOOO family of regulations and state plans implementing the EG. Here, again, EPA proposes an approach intended to preclude the use of the Exemption. As EPA describes:

> CAA section 136(f)(6)(A) states that the WEC shall not be imposed "on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111." For the purpose of determining WEC facility eligibility for the regulatory compliance exemption, the EPA proposes that the compliance status of CAA section 111(b) and (d) facilities contained within a WEC applicable facility would be assessed based on compliance with the applicable methane emissions requirements for the Oil & Natural Gas Source Category (40 CFR part 60, subparts OOOOa, OOOOb, and OOOOc).

The statutory language gives EPA wide latitude to determine what constitutes compliance with the federal and state regulations. There is nothing in this language that prohibits EPA from using a test such as substantive compliance which would be appropriate, despite EPA's assertion otherwise.

In fact, to create a fair compliance test, there are several key components that should be included. First, the compliance test should be substantive compliance, not some shallow failure to adhere to some trivial detail. Second, the noncomplying events should be identified as a result of regulatory actions by the appropriate governing regulator. Third, the events should be adjudicated to assure that they are actual noncompliance with fines, penalties or specific performance actions assessed. Fourth, only the applicable facility where the noncompliance occurred should be denied the Exemption; other applicable facilities should not be affected.

Auditing, Compliance and Enforcement

EPA devotes two paragraphs of largely boilerplate material describing its auditing, compliance and enforcement policies. Nothing in them suggests that EPA has any intent not to use these authorities in the harassing fashion that has been the history of its actions related to the American oil and natural gas production industry.

The creation of the Methane Tax gives pervasive and largely unfettered opportunities to use auditing and enforcement actions to adversely affect oil and natural gas producers. EPA can audit any producer, challenging every calculation that is made, or challenging whether a small producer should have filed Subpart W and Methane Tax information. It can threaten large and crippling fines without any standards regarding the development of the information.

IPAA has raised this issue previously because of past experiences with the Office of Enforcement and Compliance Assurance (OECA). OECA's actions to target small businesses with crippling fines generates a harsh adverse dynamic. Since EPA seems intent on using the

Methane Tax to capture small businesses and marginal wells in its scope, EPA needs to determine how it will use these enforcement tools and make those policies public. It has not.

Conclusion

IPAA opposed the Methane Tax when it was being developed. It is clearly a punitive tax, cast as a backstop to the Subpart OOOO family of regulations. It presents itself as necessary to deal with an urgent need to reduce American methane emissions in the context of a global climate challenge; however, it only addresses the thirty percent of American methane emissions from the oil and natural gas industry, leaving the other seventy percent untaxed. That seventy percent is also largely unregulated; certainly, it is not regulated to the extent of oil and natural gas. The Methane Tax exemplifies the worst in legislation – no hearings, no committee reports, no conference report, no statements during floor debate. Now, EPA is using its regulatory authority to interpret the statute to consistently increase the taxable entities, to increase emissions calculations and to increase waste emissions thresholds while limiting the availability of the Exemption. IPAA urges EPA to reverse this course, withdraw this proposal and the Subpart W proposal, and limit the adverse effects of the Methane Tax.

If IPAA can provide further information, please contact Dan Naatz at dnaatz@ipaa.org.

Sincerely,

Dan Naatz

Dan Naatz
Chief Operating Officer and
Executive Vice President

APPENDIX A

IPAA Comments: Greenhouse Gas Reporting Rule: Revisions and Confidentiality
Determinations for Petroleum and Natural Gas Systems
September 30, 2023

IPAA
INDEPENDENT PETROLEUM
ASSOCIATION OF AMERICA

September 30, 2023

ENVIRONMENTAL PROTECTION AGENCY
40 CFR Part 98
[EPA-HQ-OAR-2023-0234; FRL-10246-01-OAR]
RIN 2060-AV83

Re: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA). IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of American oil and natural gas wells, produce 83 percent of American oil and produce 90 percent of American natural gas.

In addition to the specific comments made herein, IPAA has joined comments submitted separately by the American Petroleum Institute (API).

These comments address proposals by the Environmental Protection Agency (EPA) to revise reporting requirements for Petroleum and Natural Gas Systems for the Greenhouse Gas Reporting Program (GHGRP) under Subpart W.

Subpart W Mandate

Initial efforts to revise Subpart W were included in 2022 as a part of a similarly titled proposal – Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Docket No. EPA-HQ-OAR-2019-0424. However, enactment of the Inflation Reduction Act (IRA) mandated that EPA revise Subpart W because of its use as the emissions basis for inclusion in and the calculation of the Methane Emissions Reduction Program (MERP) methane tax. In fact, no action taken now to revise Subpart W cannot be evaluated without considering and understanding its implications under the methane tax.

The mandate to revise Subpart W is no small task. The history of Subpart W demonstrates that its accuracy was never intended to be the basis for use as a taxing mechanism. Generally, its emissions factors were developed from limited emissions studies that were never structured to develop precise emissions estimates. The Inflation Reduction Act mandate requires EPA to:

> Not later than 2 years after August 16, 2022, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under

> subsections (e)[1] and (f)[2] of this section, are based on empirical data, including data collected pursuant to subsection (a)(4)[3], accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c)[4] is owed.

The current proposal fails to remotely meet this mandate regarding either time or substance.

One obvious element of the MERP is that its timelines for action are completely inconsistent with reality. It initiates the methane tax in 2025 based on 2024 emissions reporting while falsely promising that compliance with federal Subpart OOOO, OOOOa, OOOOb, and OOOOc regulations and emissions guidelines will void the tax when these regulations will not be fully implemented until at least 2028. Regarding the Subpart W revisions, it requires EPA to finish its revisions by August 2024. The scope of actions that must be undertaken for the full revision of Subpart W, as described in the Inflation Reduction Act, cannot be completed in a two-year window. However, rather than execute its mandated task, EPA proposes a thinly disguised cosmetic rework of the same material that has existed for years with little or no validation by EPA – and, even then, EPA does not apply its changes for a year after its mandated deadline.

If Congress intends to impose millions of dollars of taxes on methane emissions from the petroleum and natural gas industries, potentially crippling the production of millions of barrels and cubic feet of these American products, its mandate to EPA to revise the appallingly inaccurate emissions tools of Subpart W must be read as a serious and thorough methodological effort.

Such an effort would have several key elements. First, it must recognize the nature of emissions particularly from petroleum and natural gas production and production related emissions. Second, it must recognize that some emissions can be measured and others will continue to need emissions estimates from factors; these decisions will be particularly influenced by the economic status of the facility operator. Third, it must recognize that EPA will need to validate these measurement tools and the emissions factors.

Emissions from petroleum and natural gas systems are characterized by leaks from pieces of equipment that cannot be readily or continuously measured. They differ by an array of numerous factors – crude oil versus natural gas, associated gas or low volatility crude, wet or dry gas wells. All wells decline as they produce, changing the volume and composition of their production. Studies have shown that low production wells differ from high volume wells. The economics of production differs between high and low production wells, frequently an indication of the capitalization of the operations. The amount of active equipment at a facility changes with production. Some facilities have gathering and compression equipment on site; others do not. Many low production wells do not operate daily. Many small natural gas wells have booster compressors to suck natural gas from the well bore. Emissions analyses show that 90 percent of

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[1] Emissions charge amount

[2] Waste emissions threshold

[3] Direct and indirect costs required to administer this section, prepare inventories, gather empirical data, and track emissions

[4] Waste emissions charge

emissions come from about 10 percent of facilities, with storage tanks and some pneumatic controllers accounting for the predominant percentage of these emissions.

Because so many of the potential emissions sources from petroleum and natural gas production facilities are diverse components like valves, flanges, storage tanks, connectors, and controllers that are individually small, there are not straightforward methods to routinely monitor these emissions. Studies that have been conducted have used methods like bagging equipment to collect emissions for a short period of time. This technique is infeasible for routine operations. Newer facilities with higher volumes of production and more equipment at a site have been able to collect emissions from equipment like pneumatic controllers and pneumatic pumps and route them to vapor capture or combustion. However, such technology is limited if not impossible for older, low production facilities. Consequently, while EPA has been directed to expand the use of actual facility-based emissions data to quantify emissions, there will continue to be a certain need for emissions factors for emissions that are too difficult to measure or too expensive to collect for low production operations.

Perhaps most importantly for EPA and where EPA has failed most clearly in this proposal is the need to produce validated emissions calculations and validated emissions factors for Subpart W. Subpart W presents a long history of relying on limited studies from the 1990s appended using questionable analyses by environmental lobbyists to produce reports on petroleum and natural gas production facilities. Many of these same analyses have been used for the development of EPA methane regulations in Subpart OOOO, OOOOa, OOOOb and OOOOc. Missing from all these EPA actions is careful, thorough validation of the analyses by EPA and replication of these analyses. Many of these studies have been based on a small number of facilities, based on drive-by analysis with no information on facilities' operation, based on recalibrating data in different ways without any new information, based on applying statistical manipulation to produce headline grabbing allegations. Congress' mandate to EPA is connected to very real methane tax consequences. EPA cannot meet this mandate without collecting and analyzing its own data to develop sound, robust emissions calculation methods and emissions factors. This proposal fails completely to meet this essential test.

These challenges for EPA to meet its Subpart W mandate demonstrate clearly that it cannot be done properly in the two-year window of the MERP timeline. For EPA to do it job right, it needs to get changes made to the Inflation Reduction Act to make its timelines for both Subpart W and the completion and implementation of the Subpart OOOOb regulations and OOOOc emissions guidelines to complete these actions before collecting methane taxes from American producers.

New Implications of Subpart W

When Subpart W was solely related to filing under the GHGRP, determining whether a facility needed to file and the accuracy of submitted information carried limited further scrutiny. However, because the MERP imposes a methane tax, all filing decisions now become auditable and subject to penalties under the enforcement provisions of the Clean Air Act (CAA). These new burdens compel EPA to address them in Subpart W, but it does not.

Both the MERP and Subpart W establish a filing threshold of 25,000 mt/year of CO_2eq. This threshold was set initially by EPA when it initiated Subpart W reporting to limit the burden on small businesses while maintaining reporting by the preponderance of emissions sources. It was specifically retained in the MERP legislation. At issue then is the challenge to small producers to determine whether they are subject to the Subpart W filing requirements without compelling them to complete a costly full-blown inventory that is unnecessary. EPA provides no simple estimating procedure to determine whether small producers are near the 25,000 mt/year threshold. Both EPA and Congress have shown that small producers are not the target of the methane tax; however, EPA must now provide a mechanism to easily exclude them without the threat of audit and enforcement by the Office of Enforcement and Compliance Assurance (OECA).

A different, but similar, issue arises for all reporting entities. With Subpart W becoming the basis for the methane tax, any and all information submitted become the subject of audit and enforcement under the CAA. This creates the potential for frivolous and harassing actions by OECA. The history of OECA interaction with American petroleum and natural gas producers has been characterized by OECA actions to target smaller producers with fine threats that would bankrupt them. These actions have included interpretations of regulations by OECA that differed from the interpretation and guidance from the regulatory authors within EPA. Filing under Subpart W creates hundreds of thousands of opportunities to challenge any submitted information. Since EPA has proposed numerous different approaches to submitting information and creates the opportunity for reporters to submit facility specific information, EPA must now assure that good faith actions by reporters are not windows of opportunity for OECA to pursue harassing actions. However, EPA has not provided clear and straightforward guidance in this Subpart W proposal. Nor has it shown that OECA will use such guidance.

Property Transfer

When property transfers, the reporting of emissions takes on a different context because of the introduction of the methane tax. Previously, these issues have been largely related to assuring that there was a source responsible for assuring emissions were reported. The methane tax changes the process because substantial amounts of money are involved and there are equities that need addressed. Essentially, no new owner should be responsible for the methane taxes generated by the prior owner. This EPA proposal regarding the transfer of property fails to set forth clear delineations to create the equity that is essential.

Facility Definition

When EPA set its facility definition for the GHGRP, it was based on the 25,000 mt/year on information indicating that it would exclude small wells and producers. However, experience is showing that the current structure of the definition is capturing facilities comprised of low production wells and gathering and boosting facilities (that were not part of the original threshold selection). EPA is now proposing that emissions calculations be made at the well pad level. It should also revise the facility definition to exclude low production wells and to alter the gathering and boosting calculation to limit the use of arbitrary emissions estimates based on pipeline mileage.

Specific Proposals

EPA actions to revise component emissions factors raise serious questions about both the approach and the proposal. As discussed above, the Inflation Reduction Act mandate to revise Subpart W requires EPA to conduct thorough analyses of the numerous emissions factors and either independently validate them or develop its own valid factors. It failed to do either.

Instead, it turned to three reports as the basis for new emissions factors. These reports are generally referenced as Zimmerle[5], Pacsi[6] and Rutherford[7].

However, EPA's use of these materials demonstrates a callous disregard for the mandate EPA must meet in revising Subpart W. The Zimmerle report addresses emissions from gathering compressor stations; the Pacsi report addresses emissions from oil and natural gas production equipment leaks. Each of these studies conclude that the current emissions factor calculation process under Subpart W overstates emissions that they studied. The Zimmerle report states:

> Combining study emission data with 2017 GHGRP activity data, the study indicated statistically lower national emissions of … 66% … of current GHGI estimates, despite estimating 17% … more stations than the 2017 GHGI ….

The Pacsi report states:

> The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22% to 36% for the sites surveyed in this study as compared to direct measurements of leaking components because of a lower frequency of leaking components in this work than during the field surveys conducted more than 20 years ago to develop the current EPA factors.

To show the EPA lack of regard for its mandate, EPA ignores these conclusions and cherry picks elements of the reports to increase the component emissions factors in Subpart W. The Rutherford study takes a different approach. It makes the assumption that component based emissions estimates understate actual emissions because it believes that ambient monitoring presents more accurate results. Consequently, it surveys a variety of component based emissions studies to create emissions factors higher than those in the current Subpart W and adopts them as more accurate.

Critically, EPA embraces all these various changes that increase the Subpart W emissions factors, but it never attempts to independently validate them. The effect of this action is increases in virtually every component emissions factor, some of which would yield emissions estimates 5 times or more than the current Subpart W calculations. Not only is this approach a clear dereliction of EPA's responsibilities, but it also has the effect (along with changing the GWP for methane) of de facto lowering the 25,000 mt/year threshold and raising the emissions subject to methane tax. Enverus Intelligence Research, a subsidiary of the energy-focused Software as a Service firm Enverus, has found the proposed regulations would more than double 2021 reported methane and increase overall carbon dioxide-equivalent emissions by 41%. If EPA is intentionally revising the Congressionally enacted methane tax through its rulemaking actions, it should be held to a standard that requires it prove that its revisions are valid.

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[5] Zimmerle, D., *et al.* "Methane Emissions from Gathering Compressor stations in the U.S." *Environmental Science & Technology* 2020, 54(12), 7552-7561, available at *https://doi.org/10.1021/acs.est.0c00516*.

[6] Pacsi, A. P., *et al.* "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." *Elem Sci Anth*, 7: 29, available at *https://doi.org/10.1525/elementa.368*. 2019

[7] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al. Closing the methane gap in US oil and natural gas production inventories*. Nat Commun 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4*

Intermittent Pneumatic Controllers

EPA is proposing a series of different emissions calculations for intermittent pneumatic controllers – one of the largest emissions sources at production facilities based on the current EF. While using more accurate analysis is highly desirable, these proposals have not been independently verified by EPA. Additionally, this approach requires much higher data acquisition for each controller which could be burdensome for smaller companies. At the same time EPA eliminates the EF for intermittent pneumatic controller rather than modify what has clearly been a flawed EF.

Each EF carries with it a history of its development and evolution. Intermittent pneumatic controllers used in oil and natural gas production have been an example of the challenge of developing accurate information. Intermittent pneumatic controllers operate only when they activate. Correspondingly, they emit when they activate unless they are failing for some reason. Intermittent pneumatic controllers are one of the most pervasive pieces of equipment at oil and natural gas production facilities. Consequently, they are one of the largest emissions sources for these operations. At issue is the validity of the EF and the proposed revisions for this equipment.

To illustrate the issue, EPA need look no farther than its own proposed GHGRP revisions for calculating emissions associated with intermittent-bleed pneumatic devices, both those from the 2022 proposed rule (Docket ID No. EPA-HQ-OAR-2019-0424) and those from the 2023 proposed rule that is the focus of these comments (Docket ID No. EPA–HQ–OAR–2023–0234; FRL–10246–01–OAR). The first obvious observation is that the EPA cannot itself decide how to accurately calculate emissions from pneumatic devices, as evidenced by the widely varying proposed revisions.

The current GHGRP - Subpart W rules require reporters to calculate emissions from intermittent-bleed pneumatic devices by:

Utilizing Equation “W-1”, where

- EF_t = 13.5 scf/hr/component for intermittent-bleed pneumatic device vents (from Table W-1A), and
- T_t = Average estimated number of hours in the operating year the devices, of each type “t”, were operational using engineering estimates based on best available data. Default is 8,760 hours. (every hour of every day in a year)

In the 2022 Proposed GHGRP – Subpart W revisions for calculating emissions from intermittent-bleed pneumatic devices, the EPA proposal allowed one of two calculation methods:

- Utilize Equation “W-1A”, where
- EFt = 8.8 scf/hr/component for intermittent-bleed pneumatic device vents (from Table W-1A), and
- Tt = Average estimated number of hours in the operating year the devices, of each type “t”, were in service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours (every hour of every day in a year). **This represents a nearly 35% reduction compared to the current emissions factor**,

OR

- Utilize Equation "W-1B", which contemplates an entirely new proposed alternative calculation methodology allowing reporters that perform approved leak surveys (i.e. LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent-bleed pneumatic devices, and
- Proposes an EF of 24.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 0.30 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 98% reduction from the current required EF for intermittent-bleed pneumatic devices.**

And, now in its latest proposed GHGRP – Subpart W revisions for calculating emissions from intermittent-bleed pneumatic devices, the EPA proposal allows one of three calculation methods. Proposed "Calculation Method 3" is most analogous to the alternative method from the 2022 Proposed Rule and allows for the following:

- Utilize Equation "W-1C", which, similar to the method described above, allows reporters that perform approved leak surveys (i.e., LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent-bleed pneumatic devices, and
- Proposes an EF of 16.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 2.82 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 80% reduction from the current required EF for intermittent-bleed pneumatic devices.**

Although many Subpart W reporters currently perform OOOOa compliant LDAR surveys utilizing OGI cameras, in-line with the proposed GHGRP revisions, and are able to identify properly operating devices versus malfunctioning devices, the current rules do not allow the data to be used. And, as such, significantly overstates GHG emissions from intermittent-bleed pneumatic devices.

To demonstrate how GHG emissions from intermittent-bleed pneumatic devices are significantly overstated by the current GHGRP Subpart W rules versus EPA's proposed revisions from both 2022 and 2023, see the hypothetical scenario below:

Comparison of Methane Emissions Associated with Intermittent-Bleed Pneumatic Devices as Determined by Current GHGRP "Eq. W-1" v. 2022 Proposed GHGRP "Eq. W-1A" AND "Eq. W-1B" v. 2023 Proposed GHGRP "Eq. W-1C" (aka "Calculation Method 3")

Assumptions:
- One Subpart W Reporter
- 100 Intermittent-bleed Pneumatic Devices @ 20 Locations
- Performs compliant OGI leak surveys at all 20 locations one-time per annum
- Identifies 10 malfunctioning (i.e. leaking) Devices (10% leak rate)
- Remaining 90 Devices, verified to be operating normally
- Uses default of 8760 hours for device "operating" (current rule) and "In-service" (proposed rule) times
- Produces dry gas with a 98% CH4 Fraction

Current – "Eq. W-1"	$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1) **100 devices x 13.5 scf/hr/device x 0.98 CH4 % x 8760 hours = 11,589,480 scf CH4 emissions**
2022 Proposed – "Eq. W-1A"	$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1A) **100 devices x 8.8 scf/hr/device x 0.98 CH4 % x 8760 hours = 7,554,624 scf CH4 emissions**
2022 Proposed – "Eq. W-1B"	$E_i = GHG_i * \left[\left(24.1 * \sum_{z=1}^{x} T_z\right) + \left(0.3 * Count * T_{avg}\right)\right]$ (Eq. W-1B) **0.98 CH4 % x [(24.1 scf/hr/device x 10 leaking devices x 8760 hours) + (0.3 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 2,300,726 scf CH4 emissions**
2023 Proposed – "Eq. W-1C"	$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{16.1 \times T_{mal,z} + 2.82 \times (T_{t,z} - T_{mal,z})\} + (2.82 \times Count \times T_{avg})\right]$ (Eq. W-1C) **0.98 CH4 % x [10 leaking devices ((16.1 scf/hr/device x 8760 hours) + (2.82 scf/hr/device (8760 hours – 8760 hours)) + (2.82 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 3,560,975 scf CH4 emissions**

Summary – In the scenario above, current GHGRP requirements ("Eq. W-1") overstate methane emissions associated with intermittent-bleed pneumatic devices by approx. 35% compared to 2022 proposed GHGRP alternative 1 ("Eq. W-1A"), by approx. 80% compared to 2022 proposed GHGRP alternative 2 ("Eq. W-1B") and by approx. 69% compared to 2023 proposed GHGRP Calculation Method 3 ("Eq. W-1C").

This example demonstrates that the agency is well aware that current GHGRP rules and associated mandated calculation methodologies significantly overstate emissions for intermittent-bleed pneumatic devices.

IPAA generally supports EPA's proposal to allow multiple calculation methods for determining emissions from natural gas driven intermittent-bleed pneumatic devices. However, there are concerns with each proposed method as described below:

Calculation Method 1 – Direct measurement with flow monitoring device

This calculation method as an alternative for reporters that have or can cost-effectively install flow monitoring devices to directly measure fuel gas supplied to intermittent-bleed pneumatic devices. For many, if not most, reporters that do not already have flow monitoring devices installed, it will be cost prohibitive to install these devices and currently this is the only proposed method that fully allows the use of "empirical data" as mandated by the IRA. Consequently, EPA should amend calculation Methods 2 & 3 as described below.

> Calculation Method 2 – Direct measurement of device vent rates and use of "In-service" times

This proposed calculation method allows reporters to use empirical data in the form of direct measurement to determine vent rates from intermittent-bleed pneumatic devices. Unfortunately, this method, as proposed, is only a half-solution, in-terms of allowing empirical data, because it still requires reporters to use the non-empirical factor of "in-service (i.e., supplied with natural gas)" hours to calculate emissions.

Under proposed Calculation Method 2, reporters are required to determine emissions using the actual "number of hours the pneumatic device was in-service (i.e., supplied with natural gas) in the calendar year" for devices where vent rates were measured AND to use proposed "Eq. W-1B" for devices that did not have vent rates directly measured during the calendar year. Variable "T_t" in proposed Eq. W-1B, requires reporters to determine the "Average estimated number of hours in the operating year the devices of each type "t", were in-service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours." In both instances the requirement to determine emissions based on the concept of "in-service" hours completely contradicts the IRA mandate to allow the use of "empirical data."

Interestingly, EPA proposes that, absent any measured volume during a 5-minute or 15-minute sampling period, as applicable, reporters can use "company records or engineering estimates" to estimate per actuation emissions and actuation cycle counts to estimate emissions. See the proposed rule excerpt below:

> For intermittent bleed devices, the lack of any emissions during a 5-minute or 15-minute period, as applicable, would indicate that the device did not actuate and that the device is seating correctly when not actuating. As such, we are proposing that engineering calculations would be made to estimate emissions per activation and that company records or engineering estimates would be used to assess the number of actuations per year to calculate the emissions from that device for the reporting year." (FR p. 50311)

This approach represents "empirical data" consistent with the IRA mandate and would yield more accurate emissions estimates for intermittent-bleed pneumatic devices. As such, EPA should amend the Calculation Methods 2 & 3 to allow the use of this approach more broadly, in lieu of the "In-service" hours concept and not only when there is a lack of emissions measured during a sampling period, but in all cases.

Under proposed Calculation Method 2, EPA proposes to require the vent rate for every pneumatic device to be directly measured every 5 years. This measurement frequency is overly burdensome and unnecessary to determine a statistically representative average vent rate for devices of the same type (i.e., intermittent bleed). EPA should amend the proposed rule to only require 10% of devices to be surveyed each year.

Further, under proposed Calculation Method 2, EPA proposes to require a 15-minute vent rate sampling period for each pneumatic device, except isolation valve actuators, which would only be required to be sampled for a minimum of 5 minutes. See excerpt below:

> We are proposing a reduced monitoring duration for isolation valve actuators specifically because these devices actuate very infrequently, and the monitoring is targeted to confirm the valve actuators are not malfunctioning (i.e., emitting when not actuating) rather than to develop an average emission rate considering some limited number of actuations." (FR p. 50311)

A reduced monitoring frequency of only 5 minutes is adequate to confirm a pneumatic device is not malfunctioning. It is not only true for isolation valve actuators, but for all intermittent bleed pneumatic devices. Accordingly, EPA should amend the proposed rule to only require a 5-minute sampling period for all devices. The currently proposed 15-minute sampling period is overly burdensome and unnecessary to accurately estimate emissions.

Calculation Method 3 – Intermittent-bleed Pneumatic Device Surveys

As EPA acknowledges in its proposed revisions to the GHGRP rule, it is possible to identify and distinguish malfunctioning or "leaking" intermittent-bleed pneumatic devices from properly operating intermittent-bleed pneumatic devices via leak surveys (see below).

> As part of our review to characterize pneumatic device emissions, we found a significant difference in the emissions from intermittent bleed pneumatic devices that appeared to be functioning as intended (short, small releases during device actuation) and those that appeared to be malfunctioning (continuously emitting or exhibiting large or prolonged releases upon actuation). For natural gas intermittent bleed pneumatic devices, it is possible to identify malfunctioning devices through routine monitoring using optical gas imaging (OGI) or other technologies.
> (FR 50312)

This alternative method for calculating emissions from intermittent bleed pneumatic devices should be included for reporters that are unable to justify the costs associated with proposed calculation Methods 1 & 2, even though it does not allow the use of empirical data.

However, proposed calculation Method 3, in its current form, like the current Subpart W rules, will still likely overstate emissions from intermittent bleed pneumatic devices significantly, because it continues to rely upon the use of one-size fits all leaker emissions factors and a determination of "in-service" hours based on a default of 8760 hours (every hour of every day in a reporting year). This approach, even though properly operating devices are confirmed via approved leak surveys, requires reporters to assume properly operating intermittent bleed pneumatic devices are leaking continuously or nearly continuously.

Properly operating intermittent bleed pneumatic devices, as acknowledged by the agency, do not vent continuously. By design and definition, intermittent-bleed pneumatic devices only vent ("process emissions") when they actuate. Therefore, EPA should amend Calculation Methods 3 to allow reporters to use "company records or engineering estimates" to determine actuation cycle counts, when the data is available, in lieu of the "In-service" hours concept. This approach would allow the use of "empirical data" and yield more accurate emissions estimates.

The currently proposed EFs for Calculation Method 3 vary significantly from the 2022 proposed rule, see table below, without sufficient basis. From available information, it appears that EPA used the Zimmerle study to develop its 2023 proposal. However, these values are based on controllers under very different operating conditions than those in the oil and natural gas production component of the industry. Experts who have evaluated the 2023 proposal conclude that the 2022 factors are more appropriate. EPA should amend the proposed leaker factors to align with the 2022 proposed rule, which was consistent with the "API Field Measurement Study: Pneumatic Controllers" (Tupper 2019)

	Whole Gas EF – Properly Operating Intermittent Bleed Pneumatic Device	Whole Gas EF – Malfunctioning Intermittent Bleed Pneumatic Device
2022 Proposed Rule	0.03 scf/hr/device	24.1 scf/hr/device
2023 Proposed Rule	2.82 scf/hr/device	16.1 scf/hr/device

Retain a Calculation Method Similar to the Current Subpart W Regulations

EPA should allow a fourth calculation method similar to the method in the current Subpart W rules and that which was included in the 2022 proposed rule, that allows small operators to use a single whole gas emissions factor-based approach for calculating emissions from intermittent-bleed pneumatic devices. EPA suggests that such an alternative is unnecessary because of the Subpart OOOOb and OOOOc proposals. However, neither of those are finalized and alternative approaches to managing emissions have been proposed. In particular, the Subpart OOOOc Emissions Guidelines are not binding on states and state regulations may continue to allow natural gas driven pneumatic controllers.

The current EF for intermittent pneumatic controllers is 13.5 scf/hour/component. This EF was developed in the mid-1990s based on data collected from 19 controllers. It is hardly an example of robust data acquisition. Since then, the validity of this EF has been consistently questioned. It has become a higher profile issue as various environmental lobbying groups have produced reports based on the GHGI that is largely developed using the GHGRP.

Over the years other studies have been done to address this EF. However, the quality of EPA's 2022 analysis of this EF that has been such a target is wanting. In general, EPA discusses six studies that have been done with information on intermittent pneumatic controllers for production operations (GRI/EPA 1996, Allen, Thoma, Prasino, OIPA and API 2019). Additionally, EPA assessed a Department of Energy study on Gathering and Boosting operations (DOE G&B). In each case EPA discusses the limitations of the studies – short sampling times with assumptions about the activation period for intermittent controllers, emissions that are calculated rather than measured, and classification issues. Then, EPA eliminates two studies (Thoma, OIPA) apparently because of their use calculated emissions (which were far lower than some of the other studies). Subsequently, it produced the following summary table:

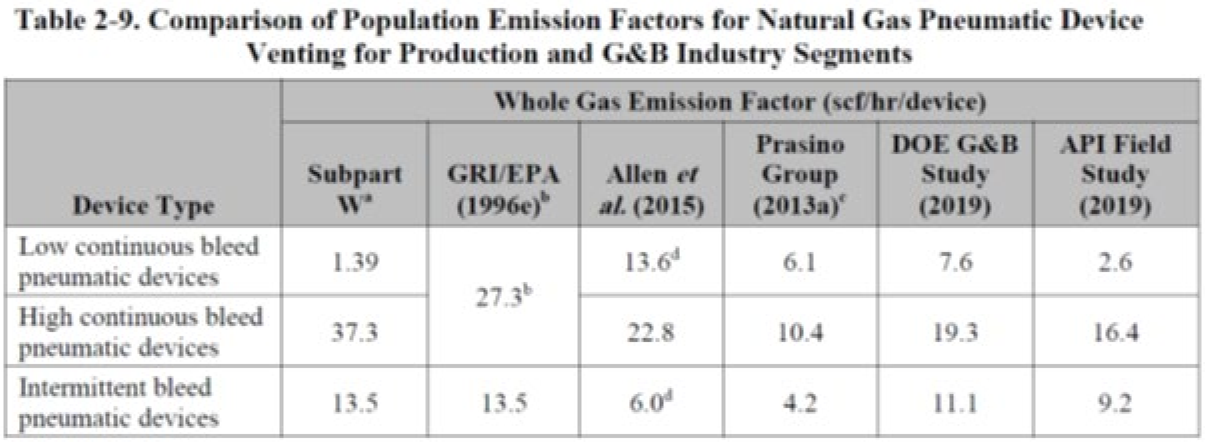

Table 2-9. Comparison of Population Emission Factors for Natural Gas Pneumatic Device Venting for Production and G&B Industry Segments

Device Type	Subpart W[a]	GRI/EPA (1996e)[b]	Allen *et al.* (2015)	Prasino Group (2013a)[c]	DOE G&B Study (2019)	API Field Study (2019)
	Whole Gas Emission Factor (scf/hr/device)					
Low continuous bleed pneumatic devices	1.39	27.3[b]	13.6[d]	6.1	7.6	2.6
High continuous bleed pneumatic devices	37.3		22.8	10.4	19.3	16.4
Intermittent bleed pneumatic devices	13.5	13.5	6.0[d]	4.2	11.1	9.2

Next, EPA averaged the intermittent factors for these studies to produce a new EF of 8.8 scf/hr. However, this appears to include the EF from the DOE G&B study; if it had not, the EF would appear to be 8.2 scf/hr. If EPA had included the Thoma and OIPA studies instead of the DOE G&B study, the EF would be 6.8 scf/hr. None of these calculations appear to be weighted based on the number of controllers tested. Consequently, for example, the 19 controllers in the GRI/EPA 1996 study are treated equally with the 128 controllers in the Prasino report. If EPA had weighted the data and used the Thoma and the OIPA studies, the EF would be closer to 3.7 scf/hr/device.

EPA should include a fourth calculation option that provides a single EF and that EF should be 3.7 scf/hr/device.

Gathering and Boosting/Centralized Production Facilities

The Gathering and Boosting category in the methane tax has an inordinately low threshold for its tax basis without any apparent justification. EPA needs to explain the source of the excess emissions fee threshold for gathering and boosting facilities and why it is appropriate. Clearly though only truly separate gathering and boosting operations should be included in it. The current Subpart W proposal creates a critical issue in this regard. The types of equipment used for gathering and boosting of natural gas can be used independently to move natural gas from production facilities to natural gas processing facilities, but it can also be used at oil and natural gas production operations as an integral part of those operations. The proposed Subpart W creates a designation of upstream operators' centralized tank batteries. "Centralized oil production sites" are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well pads". In the proposed rule, EPA has classified centralized oil production sites under the Gathering and Boosting segment. Subpart W needs to be clarified to assure that those centralized oil production operations are included within the reporting for the production facility.

Centralized Oil Production Facility Issues

EPA has recognized centralized production sites as a facility type in the proposed rule and required its emissions to be reported at the site-level, rather than per well ID, which streamlines the reporting for tank batteries. However, there are challenges with including "centralized oil production sites" in the Gathering and Boosting segment.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the Gathering and Boosting segment.

Second, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to "production supportive facilities." Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment generally results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations (even though consolidation serves to minimize environmental footprint) due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, supportive of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as "associated with a single well pad", this has created reporting confusion and centralized tank batteries have been categorized differently both by individual owners/operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb regulations, the "centralized oil production facilities" (referred to in NSPS OOOOb as "centralized production facility") are grouped under the production segment by definition rather than as Gathering and Boosting as explained below.

Currently Subpart W calls and defines the subject facility as:

> "**Centralized oil production site** means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236."

Meanwhile NSPS OOOOb/OOOOc calls and defines it as:

> "**Centralized production facility** means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

In addition, in the Pipeline and Hazardous Material Safety Administration's ('PHMSA") proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate *any* production facilities as "gathering and boosting". Specifically, as defined in API's

Recommended Practice-80 and incorporated in 49 CFR 192: “The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. In this context:

> ‘Production Operation’ means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply.”

Both the NSPS OOOOb/OOOOc and PHMSA’s name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. In an effort to mitigate confusion and create more rule alignment, EPA should align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/OOOOc.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal, “as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs.” Also, even though EPA uses the word “gather” in the definition in OOOOb/OOOOc, these sites are still properly defined as “part of the producing operations.”

Further, the fact that EPA has proposed the definition of “centralized production sites” as sites that do <u>not</u> include compressors that are part of the Gathering and Boosting segment is puzzling. If these sites are part of the Gathering and Boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the Gathering and Boosting segment on them? This demonstrates that EPA <u>*does*</u> understand the distinction between gathering and boosting compressors that should appropriately be included in the Gathering and Boosting segment and centralized tank batteries that clearly should not.

As such, EPA should change both the name and definition of “centralized oil production site” in the Subpart W rule to match NSPS OOOOb/OOOOc, to align with other federal programs for consistency, and to reflect how the industry owns and operates these facilities. EPA should delete “associated with a single well pad” from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

Further, and most importantly, EPA’s proposed definitions are contrary to the MERP waste emissions thresholds, where gathering and boosting sites are considered “non-production”. In this language on the Waste Emission Threshold, Congress created two categories for applicability of the threshold: “Production” and “Non-Production”. The Gathering and Boosting segment (segment #8) is listed under “Non-Production”. Clearly, Congress did not intend for sites associated with production, such as “centralized **production** sites” to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the Gathering and Boosting segment in the past but for application of the tax, these sites should be considered production. Doing otherwise would result in an inequitable application of the tax that would most likely not be applied uniformly by all upstream operators. If EPA does not wish to clear up the confusion and include centralized production sites in the Production segment, EPA should carve out these sites for threshold determination and make these sites subject to the 0.2% threshold as Congress has clearly mandated in the law.

In addition, the categorization of a centralized production site into Gathering and Boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane taxes that may accompany categorizing production sites as Gathering and Boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installations, dramatically increasing the amount of equipment in the field and increasing GHG emissions.

Gathering and Boosting Emissions Factor Issues

A consistent criticism of the current emissions estimation process for gathering and boosting operations relates to its use of emissions factors based on the mileage of pipelines. These factors cannot be altered based on any operational actions other than changing the nature of the pipeline material or structure. These factors from 1996 are unchanged in this proposal despite studies showing that pipeline emissions are overestimated. The consequence of this failure will be to impose the harshest excess emissions tax on this essential component of the natural gas value chain without providing any plausible recourse to alter the emissions calculations. This inaction by EPA flies in the face of its mandate to make the Subpart W emissions estimate more accurate, more reflective of actual operations.

Pipelines are inspected routinely, leaks are fixed, and emissions are eliminated. Only actual emissions should be reported under Subpart W and used for any excess emissions tax calculation; not simply based upon miles of pipeline for which the vast majority are not leaking. There should be an option to demonstrate that emissions are being managed, to show that there are no leaks, or, where leaks are identified, the emissions be based on the leaks found

Pipeline leaks are easily detected through regular inspection using airborne overflights, easement riding and operator inspections. Arguably, these have lower detection limits based on the type of technology used. Larger leaks can easily and quickly be determined by sudden drops in production. The pipeline can be isolated, and the volume of gas lost can easily be determined with great accuracy. Following are some options to determine pipeline factors and credit for inspection:

> Pipeline flyovers have a lower detection limit but do detect methane. If no leaks are found, then no emissions factor should be used for that segment and there should be no excess emissions tax or emissions calculated.
>
> Similarly, when laser-based and acoustic based technology is employed while riding the pipeline easement, leaks are detected. If no leak is detected, then no excess emissions tax or emission factor should be used. If a leak is found, then the actual leak can be measured or an emission factor should be developed. This is currently allowed in the detection of fugitives and a comparable approach for pipelines can be developed.

Use of Advanced Monitoring and Measurement Technologies

For many source categories under Subpart W, EPA has included several options for operators to be able to provide empirical data, such as measurement with metering or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. Some operators have included these technologies in their voluntary methane management programs. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.

Large emissions events

The comments filed by API extensively address the complexity and flaws in the EPA Subpart W proposal on large emissions events. IPAA commends these comments, which it joined in submitting, as a detailed assessment of the issues that need to be resolved.

Flares

The comments filed by API extensively address the complexity and flaws in the EPA Subpart W proposal on emissions issues related to oil and natural gas production flaring. IPAA commends these comments, which it joined in submitting, as a detailed assessment of the issues that need to be resolved.

Environmentalists' Recommendations Inappropriate and Unworkable

As a component of its efforts to suppress American oil and natural gas production, professional environmental lobbying organizations have orchestrated initiatives to press for additions to the Subpart W reporting regulations that are either inappropriate or unworkable. This effort was evident during the August 2023 EPA public hearing on its current Subpart W proposal where about 40 testifiers used exactly the same terms to demand changes to the Subpart W proposal. These demands reflect comments made by the Environmental Defense Fund in several forums regarding Subpart W and the methane tax.

Following is a list of the key demands:

- Integrating top-down, basin-level data alongside site- and equipment-level measurement data. Top-down, basin-level data provides a full picture of total emissions in a region, while site-level, population-based measurement data can provide insights of emissions at a finer resolution, all of which strengthen the accuracy of reported emissions.
- Building in appropriate statistical analysis of measurement data to provide a representative assessment of pollution at the facility and basin levels. Measurement data requires statistical analysis to account for intermittent emission events that may be missed by individual, one-time measurements.
- Defining guardrails and requiring independent verification for self-reported measurements from companies to ensure any company reported data accurately represents operations and is not limited to unrepresentative sites or equipment known to have lower emissions.

One of the key issues here is the relationship between these recommendations and Subpart W. Everyone would like to have the relationship between top-down basin-level data and site- and equipment-level measurement data better understood to resolve the recurring contentious debates regarding these issues. However, such an analysis is well outside the scope of facility reporting under Subpart W. Subpart W is predicated on individual companies reporting emissions estimates based on artificially contrived facilities, e.g., all their operations in an APGA basin. Even if EPA alters the reporting structure to require reporting by well pad, the reporting remains a company-based report. Conversely, basin level data is just that – basin level. It contains information that reflects emissions from numerous well pads, owned and operated by different companies. Moreover, Subpart W information reports annual emissions; top-down basin-level data is temporal in nature perhaps hours, perhaps days, perhaps minutes. No analysis that compares the top-down data and equipment-level measurement data can realistically use Subpart W reporting. These analyses must have a coordinated effort to assess data from both components simultaneously.

Similarly, while statistical analysis can be valuable, it is not in the purview of Subpart W reporting. If EPA wants to conduct appropriate statistical analysis, it must design a more rigorous direct sampling or estimating strategy. Such an effort could be valuable if developed by and validated by EPA. To date, the analyses that have been generated have been thinly veiled advocacy efforts designed to press for regulations so quickly that EPA has never developed a full and accurate understand of the emissions profiles of oil and natural gas production operations.

The final recommendation reflects the environmental lobbying position that only it can be trusted; everyone else must be put to a higher level of scrutiny. The American oil and natural gas production industry is committed to managing its emissions, including methane emissions. It has invested millions of dollars in meeting its requirements and will continue to make necessary investments. While differences may exist regarding the best, most cost-effective actions that should be taken, producers will continue their commitment to protect the environment. Certainly, the idea of having independent verification of self-reported emissions data is appealing. Presently, many of the Subpart W reports are prepared by independent consultants because of the complexity of the current requirements, particularly for smaller producers. The larger issue may well be whether the restructuring of Subpart W reporting in the context of the methane tax will adversely affect access to independent consultants. This issue has arisen in previous EPA NSPS regulations where EPA required professional engineers (PE) to certify information. Two issues arose. First, there were not enough PEs with expertise to undertake the tasks. Second, the license risks for the PE in undertaking the task were too great to bring more into the arena. A similar dynamic may occur in the methane tax context. Because OECA can challenge any reported information and because OECA has a history of using its enforcement power in this industry to target smaller producers, independent contractors may conclude that the risks to their businesses to too high to participate given the magnitude of penalties under the CAA.

Taken as a whole, these environmental lobbying organizations' recommendations are either inappropriate in the context of Subpart W or unworkable or both.

Conclusion

The task mandated to EPA by Congress requires the agency to comprehensively review, revise and validate its Subpart W regulations to make them accurate and reliable because of the role their implementation will play in the MERP, defining exposure and calculating its methane tax. Congress' deadline of EPA's action failed to reflect the reality of the task. EPA, faced with the choice of meeting a deadline or meeting its mandate to comprehensively revise Subpart W, chose the deadline and produced a wholly inadequate compendium of emissions calculations. At its best, the Subpart W proposal collects revisions to the current calculation process that EPA failed to validate as either accurate or appropriate. At its worst, the Subpart W proposal is a thinly disguised effort to raise the MERP methane tax rates through careful selection of higher emissions factors and unworkable calculation procedures. EPA should withdraw the current Subpart W proposal and execute its mandate to make it accurate, including taking the necessary steps to validate the emissions factors or emissions calculation procedures that it ultimately puts in place.

If there are questions or if EPA needs additional information on these comments, please contact Dan Naatz at 202-857-4722 or dnaatz@ipaa.org.

Respectfully submitted,

Dan

Dan Naatz
Chief Operating Officer
and Executive Vice President

APPENDIX B

Memorandum to Bruce Moore: Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking

June 2011

E ^{C}/R Incorporated *Providing Environmental Technical Support Since 1989*

MEMORANDUM

DATE: July 28, 2011

SUBJECT: Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking

FROM: Heather P. Brown, P.E.

TO: Bruce Moore, EPA/OAQPS/SPPD

The purpose of this memorandum is to document the development of a representative natural gas composition for use in the oil and natural gas sector rulemaking. This composition will be used to determine hazardous air pollutant (HAP) and volatile organic compound (VOC) emissions from several segments of the oil and natural gas sector.

Gas composition data was compiled from several sources across the industry. The following is a list of the sources of data used for this analysis:

- CENRAP database. "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventory", November 13, 2008. Covers the following States: Texas, Louisiana, Arkansas, Oklahoma, Kansas, Nebraska, Missouri, Iowa, and Minnesota
- GTI Database. "GTI's Gas Resource Database, Second Edition – August 2001"
- TX Barnett Shale. "Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements", January 26, 2009
- INGAA/API Compendium. "Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage Volume 1 – GHG Emission Estimation Methodologies and Procedures" September 28, 2005
- GOADS Offshore. "Year 2005 Gulfwide Emission Inventory Study" December 2007
- NREL LCA. "Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System" September 2000
- Union Gas. Chemical Composition of Natural Gas found online at http://www.uniongas.com/aboutus/aboutng/composition.asp
- Marcellus. "Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program - Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs" September 2009
- Wyoming DEQ. Speciation of Natural Gas and Condensate. Courtesy of Cynthia Madison, Wyoming DEQ

Tables 1 and 2 present a summary of the methane, VOC, and HAP contents provided in the above data sources for the production and transmission sectors, respectively, along with an identification of the basins/areas of the country covered by the gas composition.

In addition to the above, gas composition data were collected from the industry in 1995 during the development of the original maximum achievable control technology (MACT) standards for this sector. These data are presented in Tables 3 and 4 for production and transmission, respectively.[1] This 1995 GRI data represents gas samples from across the United States.

Gas Composition for Pneumatics, Equipment Leaks, and Compressors

Tables 1 and 2 also present a comparison of the 1995 GRI data to the other data sources. For production, the 1995 GRI data is well within the ranges of the other data sources which range from 1.19 to 11.6 percent for VOC by volume. The 1995 GRI data is also within the 95 percent confidence interval of the production data which range from 2.81 to 7.82 percent volume for VOC. Of the data sources that provide data on HAP emissions, the GRI data represent gas compositions across the United States, while the CENRAP, TX Barnett, and Marcellus data are specific to the regions specified in Tables 1 and 2. In addition, it can be expected that the gas composition for pneumatic controllers, equipment leaks, and compressors associated with these emissions units are associated with gas from oil wells and gas wells making the range of VOC composition widely varied. Therefore, it was determined that the 1995 GRI data was appropriate to use to develop a representative gas composition for pneumatic controllers, equipment leaks, and compressors.

For the transmission sector, the average 1995 GRI VOC concentration of 0.89 percent volume was compared to other data sources and was found to be in the range of the VOC composition, which ranged from 0.29 to 6.84 percent VOC by volume. It was determined that the 1995 GRI gas composition would be used to represent the average composition of natural gas in the transmission sector, because the other data sources represented natural gas compositions outside the U.S.[i]

The gas compositions from the 1995 GRI data were then converted to weight percents. First, because the average volume percent was not equal to 100, the volume percents were normalized for each component. Then the weight of each component present in the gas was calculated using the molecular weight (MW) for each component in pounds per pound mole (lb/lbmol) and an assumed gas volume of 385 cubic feet (ft^3), which represents one pound mole of gas. Finally, relative weight percents for each component were calculated. These weight percents are presented in Table 5.

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[i] It should be noted that the GRI data contains a statement that the BTEX data are "skewed toward high BTEX and VOC content gases…." However, the 1995 GRI data are within the ranges of the other data and very close to the average of other data identified. Therefore, these data were determined to be appropriate to use to develop a representative gas composition for pneumatics, equipment leaks and compressors.

Table 1. Gas Composition (volume %) for Production Sector

Data Source[a]	Source of Natural Gas	Area Covered	Volume %		
			Methane	**VOC**	**HAP**
CENRAP [b]	Conventional Gas Wells	11 Basins: Louisiana Mississippi Salt, Southern Oklahoma, Nemaha Uplift, Arkoma, Cambridge Arch Central Kansas Uplift, Fort Worth, Cherokee Platform, Permian, East TExas, Western Gulf, and Anadarko	87.8	3.50	0.019
GTI Database[c]	Gas Wells	Nationwide, proven reserves, and undiscovered reserves data from 462 basins/formations	82.8	3.61	n/a
INGAA	Unprocessed Natural Gas	Unknown	80.0	5.00	n/a
NREL LCA[d]	Gas Well	Worldwide	65.7	5.66	n/a
MARCELLUS[e]	Gas Well	Marcellus	97.2	2.02	0.03345
WYOMING DEQ[b]	Gas Well	Wyoming	92.4	1.19	0.08
		Minimum	**65.7**	**1.2**	**0.0**
		Maximum	**97.2**	**5.7**	**0.1**
		Average	**84.3**	**3.50**	**0.0**
Gas Composition	Production	Nationwide	83.1	3.66	0.164

n/a = not available

[a] Data from the Barnett Shale database was not speciated and therefore not included in this analysis.

[b] HAP data contains BTEX and n-Hexane

[c] HAP Speciation not provided; hexanes reported as Hexanes Plus

[d] Data provided were ranges for each pollutant (min and max). These values represent normalized averages of these values and may not be valid representations

[e] HAP data only reported for hexane

Table 2. Gas Composition (volume %) for Transmission Sector

Data Source	Source of Natural Gas	Area Covered	Volume %		
			Methane	**VOC**	**HAP**
INGAA	Pipeline Gas	Unknown	91.9	6.84	n/a
GOADS Offshore[a]	Sales Gas	Offshore Gas in the Gulf of Mexico	94.5	1.27	0.099
NREL LCA	Pipeline Gas	Worldwide	94.4	0.90	n/a
Union Gas	Pipeline Gas	United States, Western Canada, and Ontario	95.2	0.29	n/a
Minimum			**91.9**	**0.3**	**0.099**
Maximum			**95.2**	**6.8**	**0.099**
Average			**94.0**	**2.3**	**0.099**
GRI-MACT	Transmission/Unknown	Nationwide	92.7	0.89	0.014

n/a = not available

[a] HAP data contains BTEX and n-Hexane

Table 3. 1995 MACT Correspondence with GRI & EC/R- Production Data

Sector	**Production**											
Site	**GRI1**	**GRI2**	**GRI3**	**GRI4**	**GRI5**	**GRI6**	**GRI7**	**GRI8**	**GRI9**	**GRI10**	**GRI11**	**GRI12**
Mole %												
Nitrogen	2.72	0.44	0.78	0.46	0.79	1.52	1.18	1.74	1.90	1.30	0.52	6.81
Carbon Dioxide	0.04	0.90	0.29	3.37	1.00	0.38	1.67	0.68	0.00	0.47	0.54	8.12
Methane	95.60	93.26	90.62	56.62	80.40	78.38	79.55	74.67	83.90	91.93	88.40	79.83
Ethane	1.04	3.16	4.31	10.87	10.41	10.88	10.40	12.57	7.90	3.80	7.25	2.89
Propane	0.33	1.14	1.90	13.90	4.25	5.41	4.15	5.98	3.86	1.23	1.53	0.94
Butanes	0.16	0.64	1.15	8.59	1.65	2.10	1.74	2.55	1.70	0.70	0.90	0.54
Pentanes	0.07	0.22	0.51	3.61	0.65	0.77	0.69	1.21	0.49	0.24	0.36	0.30
Hexanes+	0.03	0.20	0.37	2.03	0.60	0.36	0.43	0.35	0.17	0.24	0.42	0.52
ppmv												
n-Hexane	88.7	277	664	2783	965	1173	937	2125	517	307	510	681
Isooctane	8.0	31.5	63.5	1552	151	145	112	103	52.0	49.6	32.0	87.0
Benzene	4.9	257	218	328	294	74.4	294	102	57.9	143	617	196
Toluene	2.9	108	117	251	468	92.4	263	31.4	45.6	142	222	213
Ethylbenzene	0	19.7	6.7	27.3	14.5	4.3	3.3	0.8	1.2	11.2	9.0	10.4
m,p-Xylenes	0	34.0	26.6	26.0	87.9	21.7	16.7	1.7	7.3	56.6	45.0	66.0
o-Xylene	0	19.9	5.0	6.2	16.1	3.2	2.4	0.3	0.6	16.9	10.0	16.4

NR = Not Reported

Table 4. 1995 MACT Correspondence with GRI & EC/R (Transmission Data)

Sector	Transmission		Unknown[a]		Transmission	Unknown[a]	Transmission					
Site	GRI13	GRI14	GRI15	GRI16	GRI17	GRI18	GRI19	GRI20	GRI21	GRI22	GRI23	GRI24
Mole %												
Nitrogen	9.89	8.68	2.96	2.55	0.22	1.25	1.16	1.1	1.15	1.12	0.3	1.85
Carbon Dioxide	0.28	0.40	0.58	0.54	0.35	2.62	0.15	0.12	0.07	1.06	1.36	0.66
Methane	81.97	82.61	91.8	92.7	97.4	95.4	98.5	88.2	81.1	94.6	95.8	93
Ethane	6.84	7.06	3.68	3.35	1.94	0.31	0.09	9.69	11.8	2.81	2.03	3.13
Propane	0.78	0.99	0.59	0.52	0.042	0.075	0.005	0.67	3.95	0.155	0.4	0.8
Butanes	0.14	0.17	0.159	0.148	<0.006	0.059	<0.006	0.035	1.189	0.116	0.075	0.314
Pentanes	0.04	0.05	0.045	0.042	<0.003	0.039	<0.003	<0.003	0.341	0.039	0.014	0.132
Hexanes+	0.04	0.03	0.042	0.042	0.004	0.202	<0.002	<0.002	0.226	0.129	0.015	0.103
ppmv												
n-Hexane	63.2	66.9	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Isooctane	17.5	14.5	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Benzene	5.0	7.9	51	36	<0.2	471	<0.2	<0.2	10	<0.2	4.5	15
Toluene	5.1	8.1	16	13	<0.1	100	<0.1	<0.1	13	<0.1	3.7	14
Ethylbenzene	0.5	0.6	3	3	<0.1	15	<0.1	<0.1	9	<0.1	0.1	1
m,p-Xylenes [1]	1.4	2.2	12	7	<0.1	11	<0.1	<0.1	1	<0.1	0.6	3
o-Xylene [1]	0.4	0.4										

[1] Sites 15-36 reported only a total xylene result that includes all xylene isomers.

NR = Not Reported

[a] Based on the high methane content (greater than 90 percent) of this datapoint, it was assumed that they were samples from the transmission segment.

Table 4. 1995 MACT Correspondence with GRI & EC/R - Transmission Data (Continued)

Sector	Transmission					Unknown[a]	
Site	GRI25	GRI26	GRI27	GRI28	GRI29	GRI30	GRI31
Mole %							
Nitrogen	1.24	1.75	1.02	1.04	0.49	0.42	0.54
Carbon Dioxide	0.3	0.13	0.44	0.65	1.76	0.87	0.92
Methane	90.2	97.8	96.6	96.1	95.5	96	95.7
Ethane	7.02	0.26	1.78	1.86	1.74	2	2.12
Propane	1	0.014	0.091	0.213	0.351	0.413	0.414
Butanes	0.146	<0.006	0.025	0.06	0.093	0.181	0.175
Pentanes	0.03	0.0015	0.0089	0.0218	0.0354	0.0675	0.0665
Hexanes+	0.021	0.0037	0.0052	0.0219	0.0322	0.073	0.069
ppmv							
n-Hexane	NR	NR	NR	NR	NR	NR	NR
Isooctane	NR	NR	NR	NR	NR	NR	NR
Benzene	9	1.2	0.8	6	7	59	58
Toluene	13	0.4	<0.4	6	6	23	26
Ethylbenzene	<0.3	0.3	<0.1	0.3	0.5	1.8	2
m,p-Xylenes [1]	4	0.2	<0.1	1	1.5	7	5
o-Xylene [1]							

[1] Sites 15-36 reported only a total xylene result that includes all xylene isomers.

NR = Not Reported

[a] Based on the high methane content (greater than 90 percent) of this datapoint, it was assumed that they were samples from the transmission segment.

Table 5. Gas Composition Conversion to Weight Percent

Component	MW (lb/lbmol)	Production				Transmission			
		Avg Vol %[b]	Normalized Vol %	Weight per 385 ft^3 Gas (lbs)	Weight %	Avg Vol % [b]	Normalized Vol %	Weight per 385 ft^3 Gas (lbs)	Weight %
Carbon Dioxide	44.01	1.46	1.5%	0.002	3.2%	0.70	0.70%	0.001	1.8%
Nitrogen	28.02	1.68	1.7%	0.001	2.3%	2.04	2.0%	0.001	3.3%
Methane	16.04	82.76	82.9%	0.035	65.7%	92.68	92.8%	0.039	86.2%
Ethane	30.07	7.12	7.1%	0.006	10.6%	3.66	3.7%	0.003	6.4%
Propane	44.09	3.72	3.7%	0.004	8.1%	0.60	0.60%	0.001	1.5%
Butane	58.12	1.87	1.9%	0.003	5.4%	0.16	0.16%	0.000	0.55%
Pentane	72.15	0.76	0.76%	0.001	2.7%	0.05	0.052%	0.000	0.22%
n-Hexane	86.17	0.09	0.092%	0.000	0.39%	0.01	0.0065%	0.000	0.032%
Other hexanes	86.17	0.32	0.32%	0.001	1.4%	0.001	0.00086%	0.000	0.0043%
Isooctane-a	114.23	0.02	0.020%	0.000	0.11%	0.002	0.0016%	0.000	0.011%
Benzene	78.11	0.02	0.022%	0.000	0.083%	0.004	0.0039%	0.000	0.018%
Toluene	92.14	0.02	0.016%	0.000	0.074%	0.001	0.0013%	0.000	0.0070%
Ethylbenzene	106.17	0.001	0.00090%	0.000	0.0047%	0.0002	0.00020%	0.000	0.0012%
Xylene	106.17	0.004	0.0041%	0.000	0.021%	0.0003	0.00030%	0.000	0.0019%
Total		99.85	100.0%	0.053	100.0%	99.91	100.0%	0.045	100.0%

a- Isooctane = 2,2,4, Trimethylpentane

b- Average of all gas compositions presented in Tables 1 and 2 for production and transmission, respectively.

Once the weight percents were calculated for each natural gas component, relative ratios were calculated for methane:total organic compounds (TOC), VOC:TOC, HAP:TOC, VOC:Methane, HAP:Methane, BTEX:Methane, HAP:VOC, and BTEX:VOC. These relative ratios are presented in Table 6.

Natural Gas Composition for Completions and Recompletions

The gas composition for completions and recompletions from gas wells were determined by performing a sensitivity analysis on the compositions of the gas well data using a larger sample size which included data from hydraulically fractured wells. The results of this analysis are shown in Table 7. A mean of 3.63 percent VOC with a 95 percent confidence interval that ranges from 3.30 to 3.96 percent VOC by volume was determined. Based on the summary statistics, these data appear to be reasonable for use in developing an average natural gas composition to use for completions and recompletions of gas wells.

Once it was determined that this data was appropriate, the average gas composition was calculated and then normalized so that the total volume percent equaled 100. This average gas composition is presented in Table 8. The gas composition data was then converted to weight percent by normalizing the volume percent for each component, then calculating the weight of each component using the MW for each component in lb/lbmol and a standard gas volume of 385 ft^3. Finally, relative weight percents for each component were calculated. Once the weight percents were calculated for each natural gas component, relative ratios were calculated for methane:total organic compounds (TOC), VOC:TOC, HAP:TOC, VOC:Methane, HAP:Methane, BTEX:Methane, HAP:VOC, and BTEX:VOC. These relative ratios are presented in Table 9.

A similar analysis was performed for completions and recompletions from oil wells. The results of this analysis are presented in Table 10. The average VOC composition was 11.62 percent by volume, with a 95 percent confidence interval that ranges from 6.73 to 16.5 percent VOC by volume. As was done for gas wells, the average composition was normalized. The gas composition used for completions and recompletions for oil wells is presented in Table 8. The gas composition data was converted to weight percent using the same approach detailed for gas wells and are presented in Table 9.

Table 6. Weight Ratios to Use in Estimating Emissions

	Production	Transmission
Methane:TOC[a]	0.695	0.908
VOC[b]:TOC[a]	0.193	0.0251
HAP:TOC[a]	0.00728	0.000746
VOC[b]:Methane	0.278	0.0277
HAP:Methane	0.0105	0.000822
BTEX:Methane	0.00280	0.000322
HAP:VOC[b]	0.0377	0.0297
BTEX:VOC[b]	0.0101	0.0116

[a] TOC = all organic compounds listed in Table 3.

[b] VOC = all organic compounds listed in Table 3, except ethane and methane.

Table 7. Summary Statistics of Sensitivity Analysis on Gas Composition for Gas Well and Hydraulically Fractured Wells

Methane		*VOC*	
Mean	83.238	Mean	3.630
Standard Error	0.709	Standard Error	0.170
Median	86.581	Median	3.104
Mode	0	Mode	0.000
Standard Deviation	15.207	Standard Deviation	3.626
Sample Variance	231.244	Sample Variance	13.149
Kurtosis	12.943	Kurtosis	9.258
Skewness	-3.08	Skewness	2.262
Range	99.75	Range	29.560
Minimum	0	Minimum	0.000
Maximum	99.748	Maximum	29.560
Sum	38289.387	Sum	1655.427
Count	460	Count	456.000
Confidence Level(95.0%)	1.393	Confidence Level(95.0%)	0.334

	Volume Percent		Volume Percent
(Lower of 95% conf interval)	81.844	(Lower of 95% conf interval)	3.297
Methane	83.238	VOC	3.630
(Higher of 95% conf interval)	84.631	(Higher of 95% conf interval)	3.964

Table 8. Average Gas Composition for Completions and Recompletions of Gas and Oil Wells

	Average Volume Percent	
Pollutant	**Gas Wells**	**Oil Wells**
Carbon dioxide (CO2)	1.631	1.00162
Nitrogen (N2)	4.455	29.19
Methane (C1)	**83.081**	46.73
Ethane (C2)	4.924	10.17
Propane (C3)	2.144	6.62
i-Butane (i-C4)	0.348	1.067004
n-Butane (n-C4)	0.643	2.136346
i-Pentane (iC5)	0.095	0.550849
n-Pentane (nC5)	0.119	0.515798
Cyclopentane	0.005	0.001091
n-Hexane (n-C6)	0.155	0.005182
Hexanes (C6)	0.000	-
Cyclohexane	0.001	0.001455
Other Hexanes	0.010	0.007636
Methylcyclohexane	0.002	0.001818
C6+ Heavies	0.114	-
Heptanes (C7)	0.009	0.697080
n- Heptanes (C7)	0.000	0.001909
C8+ Heavies	0.004	0.005182
Benzene	0.005	0.006182
Toluene	0.003	0.000223
Ethylbenzene	0.000	0.000445
Xylenes	0.001	-
2,2,4-Trimethylpentane	0.000	0.000223
Helium	0.140	-
Oxygen	0.084	-
Hydrogen	0.001	0.575909
Hydrogen disulfide (H2S)	2.027	0.709092
Total	**100**	**100**
VOC	**3.66**	**11.62**

Table 9. Weight Ratios to Use in Estimating Emissions for Completion and Recompletions

	Gas Wells	**Oil Wells**
Methane:TOC[a]	0.796	**0.4453**
VOC[b]:TOC[a]	0.116	**0.3729**
HAP:TOC[a]	0.0084	**0.0006**
VOC[b]:Methane	0.146	**0.8374**
HAP:Methane	0.0106	**0.0001**
BTEX:Methane	0.0006	**0.0007**
HAP:VOC[b]	0.0726	**0.0016**
BTEX:VOC[b]	0.0040	**0.0009**

[a] TOC = all organic compounds listed in Table 3.

[b] VOC = all organic compounds listed in Table 3, except ethane and methane.

Table 10. Summary Statistics of Sensitivity Analysis on Gas Composition for Oil Wells

Methane	
Mean	46.73157
Standard Error	4.196101
Median	49.63115
Mode	49.63115
Standard Deviation	19.68146
Sample Variance	387.3598
Kurtosis	1.385922
Skewness	-1.15094
Range	71.93094
Minimum	0.156
Maximum	72.08694
Sum	1028.095
Count	22
Confidence Level(95.0%)	8.72627
(Lower of 95% Conf interval)	38.0053
Methane	46.73157
(Higher of 95% Conf. Interval)	55.45784

VOC	
Mean	11.61755
Standard Error	2.193276
Median	9.697621
Mode	#N/A
Standard Deviation	7.274275
Sample Variance	52.91508
Kurtosis	1.438744
Skewness	1.127773
Range	25.91599
Minimum	1.381007
Maximum	27.297
Sum	127.793
Count	11
Confidence Level(95.0%)	4.886924
(Lower of 95% Conf interval)	6.730621
VOC	11.61755
(Higher of 95% Conf. Interval)	16.50447

REFERENCES

1. Letter and Attachments from Evans, J. M., Gas Research Institute, to G. Viconovic, EC/R Incorporated. Natural Gas BTEX Content. April 19, 1005. Legacy Docket Number A-94-04, Item II-D-35.

From: Reiten, John R.
To: Brady Pelton; Eric Delzer; Ron Ness
Cc: Norrell, Ryan; Beehler, Jace
Subject: WEC Comments
Date: Thursday, March 28, 2024 11:01:38 AM
Attachments: 3-26-24 - ND WEC Comment.pdf

Attached are ND's comments.

Have a great Easter weekend!

John Reiten
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NORTH DAKOTA
OIL AND GAS DIVISION

March 26, 2024

Submitted Electronically via Regulations.gov

Michael S. Regan
Administrator, Environmental Protection Agency
1200 Pennsylvania Ave NW, Suite 1101A
Washington, DC 20460

Re: State of North Dakota Comments on the Proposed Rulemaking Titled "Waste Emissions Charge for Petroleum and Natural Gas Systems" (Docket ID No. EPA-HQ-OAR-2023-0434; FLR-10246.1-01-OAR)

Dear Administrator Regan:

The State of North Dakota, acting by and through its Industrial Commission (NDIC) and Department of Environmental Quality (NDDEQ), respectfully submits the following comments[1] on the U.S. Environmental Protection Agency's (EPA) proposed rulemaking titled "Waste Emissions Charge for Petroleum and Natural Gas Systems," published in the Federal Register on January 26, 2024 (89 Fed. Reg. 5318) (Docket ID No. EPA-HQ-OAR-2023-0434; FLR-10246.1-01-OAR) (hereinafter the "Proposed Rule").

The Proposed Rule is intended to implement Section 136 of the Clean Air Act (CAA), which was enacted as part of the Inflation Reduction Act of 2022 (IRA). Unlike most other sections of the CAA, § 136 does not directly regulate emissions. Instead, CAA § 136 requires EPA to impose a methane emissions fee – or waste emissions charge (WEC) – on certain oil and gas sources and sets out the basic formula for calculating these fees.

However, in the Proposed Rule, EPA interprets CAA § 136 to give it authority to directly regulate methane emissions from oil and gas sources, contrary to Congressional intent and the principle of cooperative federalism that is the basis for the CAA. In addition to this fundamental flaw, the Proposed Rule has several other technical and legal defects, resulting in a proposal that fails to meet the Administrative Procedure Act's (APA) reasonableness requirement. 5 U.S.C. § 706(2)(A). Of particular concern to North Dakota are the destructive impacts that such

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[1] North Dakota also supports the comments submitted by the State of West Virginia et al. on the Proposed Rule.

unreasonable requirements have on low-producing or marginal wells. North Dakota urges EPA to withdraw the Proposed Rule and work with its state partners to develop a new proposal implementing CAA § 136's methane fee provisions in a way that complies with the IRA, CAA, and APA.

I. North Dakota's Significant Interests in the Proposed Rule.

North Dakota is ranked 3rd in the United States among all states in the production of oil and gas. North Dakota produces over 400,000,000 barrels of oil per year and over 1.1 trillion cubic feet of natural gas per year. Oil and gas production are central to North Dakota's economy and the welfare of its citizens, responsible for 54% of the value of North Dakota's economy, generating approximately 76% of tax revenue, and creating approximately 66,000 good-paying jobs. The Proposed Rule, which would force many marginal wells to be prematurely shut-in or plugged and abandoned, would have harmful impacts to North Dakota's economy by destroying the tax revenue and jobs associated with these wells.

In addition to its economic interests, North Dakota's regulatory interests would be harmed by the Proposed Rule. As a major oil-producing state, North Dakota has taken the lead role in regulating emissions from oil and gas sources for decades. NDDEQ, which is the primary delegated implementation and enforcement authority for the CAA in North Dakota, regulates emissions of methane and other greenhouse gases from oil and gas sources under its Air Pollution Control Rules, N.D. Admin. Code ch. 33.1-15. *See* N.D.C.C. § 23.1-06-04(1) (authorizing NDDEQ to implement federal CAA programs). NDIC also has rules and requirements to reduce emissions from oil and gas sources, including its Gas Capture Policy, which has significantly reduced emissions associated with flaring. Over the last decade, North Dakota's oil and gas industry has worked diligently to attain the Gas Capture Policy's goals even while production has significantly increased.[2]

II. The Proposed Rule is Premature.

As a threshold matter, the Proposed Rule is premature and should be withdrawn. There is significant uncertainty regarding related EPA rules that form the foundation of the Proposed Rule, impacting North Dakota's ability to provide meaningful comment. EPA should wait to propose a rule to implement CAA § 136 until the related rules are final and have gone through judicial review.

First, as required by CAA § 136(h), the Proposed Rule relies on data reported under subpart W, part 98 of title 40, Code of Federal Regulations ("Subpart W"). Under the statute, EPA must adopt revisions to Subpart W to address this reporting by August 16, 2024. EPA has proposed revisions

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[2] In October 2014, when the Gas Capture Policy first went into effect, gas capture for Bakken facilities was at 78% and gas capture statewide was at 77%. In October 2014, North Dakota produced 44,543,371 mcf of gas. In October 2023, gas capture for Bakken facilities was at 95% and gas capture statewide was at 94%. In October 2023, North Dakota produced 105,437,132 mcf of gas.

to Subpart W, but they have not been finalized. 88 Fed. Reg. 50,282 (Aug. 1, 2023) (to be codified at 40 C.F.R. pt. 98, subpt. W). EPA brushes past the fact that Subpart W is currently being revised by assuming the final revisions will be identical to the August 1, 2023 proposal and citing to Subpart W as if it had already been revised in that way. 89 Fed. Reg. at 5322. This approach prejudices those who submit comments on the Proposed Rule because the Proposed Rule relies exclusively on Subpart W to report the data used to calculate methane fees and commenters lack information regarding whether and how EPA will revise the reporting requirements.

Second, a central feature of the Proposed Rule, the Regulatory Compliance Exemption, is intrinsically intertwined with EPA's recently adopted OOOOb and OOOOc methane emissions requirements. *See* 89 Fed. Reg. 16,820 (March 8, 2024). Although the OOOOb and OOOOc rules are final, they are subject to litigation[3] and their fate is, therefore, uncertain. The scope of these rules may change because of judicial review. As a result, the full impact of OOOOb and OOOOc on the Regulatory Compliance Exemption is currently unknown.

III. The Proposed Rule's Regulatory Compliance Exemption is Unlawful and Unworkable.

CAA § 136(f)(6) contains an "exemption for regulatory compliance," which EPA refers to the in the Proposed Rule as the "Regulatory Compliance Exemption." Under CAA § 136(f)(6), an applicable facility that is subject to methane emissions requirements under CAA § 111(b) and (d) is exempt from methane fees if it is in compliance with those requirements. The exemption only goes into effect after EPA makes two determinations. First, EPA must determine that methane emissions standards and plans under CAA § 111(b) and (d) "have been approved and are in effect in all States with respect to the applicable facilities." CAA § 136(f)(6)(A)(i). Second, EPA must determine that the methane emissions requirements under CAA § 111(b) and (d) "will result in equivalent or greater emissions reductions as would be achieved by [EPA's proposed November 15, 2021, rule] if such rule had been finalized and implemented." CAA § 136(f)(6)(A)(ii).

EPA recently adopted methane emissions requirements for new sources under CAA § 111(b), the OOOOb rules, and existing sources under § 111(d), the OOOOc rules. EPA is proposing that the CAA § 136(f)(6) exemption is not available until the OOOOb and OOOOc rules are both in effect nationwide. 89 Fed. Reg. at 5336. As a result, the Regulatory Compliance Exemption would not be available until every state has an approved CAA § 111(d) plan implementing OOOOc. *Id.* at 5337.

Further, EPA proposes to apply a "no deviations" policy when determining a facility's eligibility for the CAA § 136(f)(6) Regulatory Compliance Exemption. 89 Fed. Reg. at 5344. This means EPA would deny the exemption to any facility – which it interprets as all assets in a basin[4] – that has *any* deviation from OOOOb rules or a state's OOOOc plan. So, an operator would be ineligible for the Regulation Compliance Exemption for all of its assets in a basin if any one of its assets in

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[3] North Dakota and other parties have filed petitions to review the rule in the D.C. Circuit Court of Appeals. *Oklahoma v. EPA*, No. 24-1059 (D.C. Cir. filed Mar. 12, 2024).

[4] As discussed in Section IV, North Dakota disagrees with the basin-wide approach.

that basin has a single wisp of unauthorized methane or if an operator makes an inconsequential error in reporting or recordkeeping.

The Regulatory Compliance Exemption as set forth in the Proposed Rule is contrary to the CAA and IRA. It exceeds EPA's authority and infringes on the role of states as the primary enforcers of the CAA. And several aspects of it are unreasonable, resulting in an exemption that is meaningless. EPA must, therefore, withdraw the Proposed Rule and work with its state partners to develop a legal and workable solution.

a. CAA § 136(f)(6) does not authorize EPA to directly regulate methane emissions.

The meaning of CAA § 136(f)(6)'s condition that a facility be "in compliance with methane emissions requirements" must be considered in the context of the OOOOb and OOOOc rules and the CAA's cooperative federalism framework. Compliance with OOOOb and OOOOc rules should be determined by the appropriate enforcement authority. Typically, this would be the states through their enforcement programs. Or, if a state has not adopted OOOOb, EPA would determine compliance as the primary enforcement authority. Only if, after the requisite due process, an appropriate enforcement authority determines in an enforcement action that a facility is not in compliance with OOOOb or a state plan implementing OOOOc, should a facility be considered noncompliant and, therefore, ineligible for the exemption.

EPA's "no deviations" policy goes beyond this plain reading of CAA § 136(f)(6). It appears to be an attempt to directly regulate methane emissions. EPA acknowledges that it intends to use the methane charge to achieve emissions reductions by stating "[t]he WEC has important interactions and is designed to work hand-in-hand with the NSPS and EG for the Oil and Natural Gas Sector[5] by accelerating the adoption of cost-effective methane mitigation technologies . . . ." 89 Fed. Reg. at 5360. EPA further claims that "this action will result in cumulative emissions reductions . . . ." *Id.* CAA § 136(f)(6) cannot be interpreted to give EPA this authority, because the IRA, as a reconciliation bill, was only for the purpose of imposing fees and not for direct regulation of emissions. *See* 2 U.S.C. § 644 (provisions in reconciliation bills that are unrelated to budgetary matters may be stricken). Bypassing state enforcement authorities would conflict with the important role of the states under the CAA. *See* 42 U.S.C. § 7401(a)(3) ("air pollution prevention . . . and air pollution control at its source *is the primary responsibility of States and local governments*") (emphasis added); and 42 U.S.C. § 7407(a) ("Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State . . . ."). Courts have rejected similar attempts by agencies to directly regulate emissions from oil and gas sources without statutory authority. *See, e.g., Wyoming v. United States DOI*, No. 2:16-CV-0285-SWS, 2017 U.S. Dist. LEXIS 5736, at *28 (D. Wyo. Jan. 16, 2017).

b. EPA's "no deviations" policy is unreasonable.

Not only is EPA's "no deviations" policy unlawful, but it is also unreasonable. Reading CAA § 136(f)(6)'s "in compliance" condition as applying to any minor deviation would lead to absurd

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[5] The "NSPS and EG for the Oil and Natural Gas Sector" are the OOOOb and OOOOc rules.

results. Requiring that a noncompliance determination be based on an enforcement authority's finding that a violation occurred using the appropriate process would help put some necessary limits on EPA's ability to exclude facilities from the exemption. Rejecting EPA's basin-wide approach for defining "facility," as discussed in Section IV, would also help avoid absurd results because methane fees would not be applied to all of an operator's assets in an entire basin based on an isolated "deviation" at one well site.

c. The exemption must be applied on a state-by-state basis.

EPA misreads CAA § 136(f)(6) by interpreting it to require that OOOOb and OOOOc state plans both be in effect nationwide for the exemption to be available. EPA's interpretation ignores the phrase "with respect to the applicable facilities." The plain meaning of CAA § 136(f)(6) is that OOOOb and a OOOOc state plan must be in effect in all states in which an applicable facility[6] is located. As soon as OOOOb is in effect, facilities subject to it should be able to claim the exemption. And once a state has an approved 111(d) plan implementing OOOOc, the exemption should be in effect for all facilities in that state that are subject to the plan. This state-by-state interpretation is consistent with CAA § 111(d), which requires state-specific implementation plans.

The Proposed Rule's implementation of EPA's Regulatory Compliance Exemption on a nationwide basis must be rejected because it renders CAA § 136(f)(6) essentially meaningless. It will take years for all states to have approved OOOOc state plans in place.[7] Delays in EPA's review and approval of state plans are often due to resource issues at the federal level or litigation relating to such plans. The Proposed Rule, and the related OOOOb and OOOOc rules, should address these concerns so that states and regulated entities are not punished by being denied the exemption due to delays beyond their control. Although it would not completely solve the problem, EPA would be better able to address such concerns by applying the exemption on a state-by-state basis.

The onshore petroleum and natural gas production data reported under Subpart W is sufficiently detailed to apply the exemption on a state-by-state basis. Owners and operators initially group data at the basin level, as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG–CSD Geologic Provinces Code Map. *See* 40 C.F.R. § 98.238 (definition of basin). But the Subpart W reports are further differentiated by the county and state where the sub-basin is located, as well as by formation type (oil, high permeability gas, shale gas, coal seam, or other tight reservoir rock). 40 C.F.R. § 98.236(aa)(1)(ii)(A-C) (onshore petroleum and natural gas production). For example, while the Williston Basin, AAPG-CSD code 395, covers all of North Dakota and parts of Montana and South Dakota, the Subpart W reporting form collects additional county-specific data.

Furthermore, applying the exemption on a state-by-state basis is consistent with the Congressional intent to encourage early compliance with methane emissions requirements. *See* 89 Fed. Reg. at

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[6] As discussed in Section IV, the best interpretation of "facility" is centralized production facility or, if the asset is not tied into a centralized production facility, an individual well.

[7] For example, there are states – including North Dakota – that do not yet have fully approved Round One Regional Haze Plans. These state plans were first required to be submitted in 2007.

5336. States would be rewarded by adopting early and compliant OOOOc plans. If the exemption were applied nationwide, there would be no incentive for states to act early.

d. EPA must attempt to construe CAA § 136(f)(6) to avoid non-delegation concerns.

The Constitution imposes limits on the delegation of legislative power to administrative agencies. *West Virginia v. EPA*, 597 U.S. 697, 750 (2022). At a minimum, Congress must provide "an intelligible principle to guide [the agency's] use of discretion." *Gundy v. United States*, 139 S. Ct. 2116, 2123 (2019) (cleaned up); *see also id.* at 2139-40 (Gorsuch, J., dissenting) (questioning whether even a few "intelligible principles" are enough to save an overbroad delegation of legislative power). This "requires construing the challenged statute to figure out what task it delegates and what instructions it provides." *Id.* at 2123.

While other aspects of the IRA and EPA's interpretation of it raise non-delegation concerns, CAA § 136(f)(6) is especially problematic. CAA § 136(f)(6)(ii) requires EPA to determine that compliance with the methane emissions requirements adopted in OOOOb and state plans implementing OOOOc "will result in equivalent or greater emissions reductions as would be achieved" by EPA's November 2021 proposed rule "if such rule had been finalized and implemented." The central flaw is that the November 2021 proposed rule contained no regulatory text and so there is no intelligible principle to guide EPA's application of the statute. Moreover, regarding OOOOc, these requirements are implemented via state plans which can take various factors into account, such as remaining useful life of the source, so it is impossible to know what emissions reductions would have been achieved by these hypothetical state plans.[8]

Although it may not be possible, EPA must attempt to construe CAA § 136(f)(6) to avoid non-delegation concerns. One acceptable reading could be that EPA should look to the final requirements in its recently adopted OOOOb and OOOOc rules, as these are the eventual outcome of its November 2021 proposed rule. In doing so, EPA must take into consideration any revisions required because of judicial review. This reading would clarify and simplify the application of the Regulatory Compliance Exemption.

IV. The Proposed Rule's Interpretation of "Facility" is Unreasonable and Inconsistent with CAA § 136.

Under CAA § 136(c), EPA is to impose a methane fee on emissions exceeding the waste emissions threshold "from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitter per year" under Subpart W. CAA § 136(d) defines "applicable facility" as a facility within one of nine listed Subpart W industry segments, including "[o]nshore petroleum and natural gas production." CAA § 136 does not define the term "facility."

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[8] As the Proposed Rule acknowledges, "because state plans were never developed pursuant to the NSPS OOOOb/EG OOOOc 2021 Proposal, there is no means of reasonably estimating the requirements that may have been included in those state plans and what emissions reductions they would have achieved." 89 Fed. Reg. at 5342.

In the Proposed Rule, EPA takes the position that a "facility" for purposes of CAA § 136 is a "facility" as defined in Subpart W. 89 Fed. Reg. at 5343. Currently, Subpart W defines "facility" for onshore petroleum and natural gas production as:

> all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO[2] EOR[9] operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

40 C.F.R. § 98.238. In other words, under Subpart W, a "facility" includes all of an operator's assets in a basin.

Nothing in CAA § 136 requires "facility" to be defined on a basin-wide basis. The statute directs that "[f]or purposes of this section, the term 'applicable facility' means a facility within the following industry segments, as defined in Subpart W of part 98 of title 40, Code of Federal Regulations." CAA § 136(d). In this sentence the phrase "as defined in subpart W" immediately follows the term "industry segments" and thus refers to "industry segments" instead of the term "applicable facility."

EPA's belief that CAA § 136 requires the agency to impose methane fees on Subpart W "applicable facilities" misreads the statute and results in an overly broad interpretation that would have severe negative consequences for North Dakota and for owners and operators of marginal wells. Defining "applicable facilities" to include all of an owner or operator's assets in a basin causes more owners and operators to exceed the 25,000 metric ton threshold by combining the emissions from multiple stationary sources. While combining emissions from all of an owner or operator's assets may be reasonable for reporting purposes because it results in a more complete inventory, it does not follow that emissions should be combined in the same manner for purposes of assessing fees. The 25,000 metric ton threshold established by Congress should be used to protect small operators and marginal wells. EPA can accomplish this by defining facilities more reasonably. Conversely, the Proposed Rule as drafted would result in more than 2,200 of marginal wells in North Dakota being subject to methane fees. As a result, these marginal wells could be shut-in and plugged and abandoned prematurely, resulting in wasted resources. Prematurely plugging and abandoning these marginal wells would cause economic harm to North Dakota in the form of lost tax revenue and lost jobs.

For purposes of onshore petroleum and natural gas production, "facility" should instead be defined as a centralized production facility or, if the asset is not tied into a centralized production facility, a single well-pad. This would reduce confusion surrounding reporting in this segment and be more

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[9] The phrase "CO[2] EOR" means carbon dioxide enhanced oil recovery.

consistent with OOOOb and OOOOc. It would also be more consistent with the common understanding of the word "facility." And, operators already report data by centralized production facility to state regulators, such as NDIC, so this should help streamline reporting. At a minimum, EPA should use the data it already receives to allocate onshore petroleum and natural gas production emissions to sub-basins at the county level.

Using the centralized production facility approach is consistent with CAA § 136 and is how emissions are currently reported for OOOO. For example, as discussed in Section III, the Regulatory Compliance Exemption must be considered on a state-by-state basis. To properly implement this exemption, it is necessary to identify facilities within each state rather than basin-wide, as basins cross state borders.

And using the centralized production facility approach would also ensure owners and operators are treated consistently across basins. The Williston Basin lies partially within Canada. There are North Dakota owners and operators who have assets on both sides of the border. If "facility" were to be defined basin-wide, methane fees would have to be assessed differently for these owners and operators because the assessment of their methane fees could not take into consideration all of their basin-wide assets. This could mean a higher or lower fee – depending on the company's assets – than the owner or operator would have if all of the Williston Basin was within the United States.

V. The Proposed Rule's Permitting Delay Exemption is Unreasonably Narrow.

CAA § 136(f)(5) contains an exemption from fees for emissions caused by delays in environmental permitting for gathering and transmission infrastructure, which EPA refers to the in the Proposed Rule as the "Permitting Delay Exemption." But the Proposed Rule's provisions implementing this exemption are so unreasonably narrow that it is rendered meaningless. This is yet another reason why EPA should withdraw the Proposed Rule and develop a new proposal that is consistent with the IRA, CAA, and APA. For example, under EPA's proposal the exemption would not be available until the permitting authority has delayed the permit for "somewhere between 30 and 42 months." 89 Fed. Reg. at 5333. This means that operators would have to pay years of burdensome fees for circumstances beyond their control. In North Dakota, where it can already be difficult to permit infrastructure needed to tie oil and gas facilities to pipelines, these unreasonable restrictions on qualifying for the exemption would be especially harmful.

In addition, the meaning of "environmental permits" is not clear. North Dakota agrees with EPA that this should include permits issued by federal, state, or local agencies, but EPA should further clarify the types of permits that would be eligible for the exemption. Permits relating to siting and zoning of pipelines, compressor facilities, gas processing facilities, and other infrastructure should be included, as these relate to environmental impacts.

V. Conclusion

For the reasons stated herein, the NDIC and NDDEQ respectfully urge EPA to withdraw the Proposed Rule and work with its state partners to develop a new proposal implementing CAA § 136's methane fee provisions in a way that complies with the IRA, CAA, and APA.

Sincerely,

Lynn D Helms

Lynn Helms, Ph.D.
Director of Mineral Resources
North Dakota Oil & Gas Division

L. David Glatt, P.E.
Director
North Dakota North Dakota Department
of Environmental Quality

From:	Brady Pelton
To:	Brady Pelton
Cc:	Micaela Rud
Subject:	YOU"RE INVITED! - ND Petroleum Council March Board Events
Date:	Monday, February 12, 2024 5:16:27 PM
Attachments:	image001.png image002.png UND EERC Luncheon and Tour Flyer.pdf
Importance:	High

Good afternoon, North Dakota leaders:

The North Dakota Petroleum Council Board of Directors and guests are eagerly awaiting our February 29-March 1 visit to Grand Forks and the University of North Dakota!

In advance of our two-day visit, we wanted to share the invitation below from the Energy & Environmental Research Center (EERC):

> You are cordially invited to a luncheon at the University of North Dakota (UND) Energy & Environmental Research Center (EERC) on Friday, March 1, 2024, at noon. Attendees include state and local leaders and North Dakota Petroleum Council members.
>
> Following the luncheon, you have an opportunity to tour the EERC or the College of Engineering & Mines (CEM). You can join the EERC for a journey through the EERC's expanding array of projects, deeply meaningful for our state, and the entire region.
>
> - Option 1: At the EERC, the tour will include, but not be limited to, research on Bakken, salt caverns, rare-earth elements, CO_2 capture and storage, development of new materials, and the latest update to our expanding hydrogen program. During the tour, you will hear from our professional research staff who bring a wealth of expertise to these impactful areas. The EERC team is looking forward to answering any questions you may have and the opportunity to connect with leadership from North Dakota and our entire region.
> - Option 2: Dean Brian Tande will lead a tour of the College of Engineering & Mines National Security Corridor and the Collaborative Energy Center. CEM research has grown by more than 40% in the past several years, with over $9M in areas such as energy, rare-earth elements, UAS, and national security.
>
> Please RSVP by February 15, 2024, for both the luncheon and the tour at this link: use this link.

Capping off the events on Friday, NDPC will host a social at the CanadInn's Playmakers Lounge from 4:30 to 6:00 p.m. and then host guests at the Ralph as UND takes on Western Michigan in some good old North Dakota hockey. Hockey tickets are sponsored by our great friends at AE2S, Construction Engineers, and the UND Alumni Association & Foundation. We have a hockey ticket for you. However, if you have access to other tickets, please use those and find us on the suite level (Suites 201 and 204; Alumni Association suite is 225).

In order to best prepare for meals and other logistics, we ask that you RSVP by February 15th at each of the links below.

Friday, March 1 - EERC Lunch & Tour Invite
Friday, March 1 - NDPC Social & Hockey Night

Thank you all for your continued support and please contact me with any questions. We look forward to seeing each of you.

Best regards,
Brady

Brady Pelton
Vice President & General Counsel

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www.NDOil.org | www.NDOilFoundation.org

UND EERC INVITES YOU TO A

LUNCHEON & TOUR @ UND

Join us at the EERC for a lunch with, state and local leaders, and the North Dakota Petroleum Council.

MARCH 1, 2024

from noon to 3:00 p.m.

Energy & Environmental Research Center
15 North 23rd Street
Grand Forks, ND 58202

CLICK HERE TO RSVP

From: Reiten, John R.
To: Helms, Lynn D.; Glatt, Dave D.; Stroh, David E.; Semerad, Jim L.
Cc: Tyler, Karen J.; Haase, Reice; Norrell, Ryan; Beehler, Jace; Nowatzki, Mike G.
Subject: Waste Emissions Charge for Petroleum and Natural Gas Systems PROPOSED RULE
Date: Friday, January 26, 2024 10:51:34 AM
Attachments: 2024-00938.pdf

Hi all,

I saw this morning the Waste Emissions Charge for Petroleum and Natural Gas Systems rule proposed by EPA made it into the Federal Register. Comment Deadline is March 11th. I did flag for Dave G. and Lynn H. but I wanted to ensure it was on everyone's radar.

"This program requires the EPA to impose and collect an annual charge on methane emissions that exceed specified waste emissions thresholds from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to the petroleum and natural gas systems source category requirements of the Greenhouse Gas Reporting Rule. The proposal would implement calculation procedures, flexibilities, and exemptions related to the waste emissions charge and proposes to establish confidentiality determinations for data elements included in waste emissions charge filings."

https://www.federalregister.gov/d/2024-00938

Dave G. did say there would probably be a high likelihood DEQ would comment. Does DMR believe it needs to comment as well? Do we need external resources to assist in the comment letter?

Thank you for your input and attention to this. The battle rages on…

Happy Friday?

John Reiten

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 2 and 99

[EPA-HQ-OAR-2023-0434; FRL-10246.1-01-OAR]

RIN 2060-AW02

Waste Emissions Charge for Petroleum and Natural Gas Systems

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing a regulation to implement the requirements of the Clean Air Act (CAA) as specified in the Methane Emissions Reduction Program of the Inflation Reduction Act. This program requires the EPA to impose and collect an annual charge on methane emissions that exceed specified waste emissions thresholds from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to the petroleum and natural gas systems source category requirements of the Greenhouse Gas Reporting Rule. The proposal would implement calculation procedures, flexibilities, and exemptions related to the waste emissions charge and proposes to establish confidentiality determinations for data elements included in waste emissions charge filings.

DATES: *Comments*. Comments must be received on or before **[INSERT DATE 45 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**.

Public hearing. The EPA will conduct a virtual public hearing on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. See **SUPPLEMENTARY INFORMATION** for information on registering for a public hearing.

ADDRESSES: *Comments*. You may submit comments, identified by Docket ID No. EPA-HQ-OAR-2023-0434, by any of the following methods:

Federal eRulemaking Portal. *https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.

Mail: U.S. Environmental Protection Agency, EPA Docket Center, Air and Radiation Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.

Hand Delivery or Courier (by scheduled appointment only): EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations are 8:30 a.m.-4:30 p.m., Monday-Friday (except Federal holidays).

Instructions: All submissions received must include the Docket ID No. for this proposed rulemaking. Comments received may be posted without change to *https://www.regulations.gov*, including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the "Public Participation" heading of the **SUPPLEMENTARY INFORMATION** section of this document.

The virtual hearing will be held using an online meeting platform, and the EPA has provided information on its website (*https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program-merp*) regarding how to register and access the hearing. Refer to the **SUPPLEMENTARY INFORMATION** section for additional information.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Mr. Shaun Ragnauth, Climate Change Division, Office of Atmospheric Programs (MC-6207A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW, Washington, DC 20460; telephone number: (202) 343-9142; e-mail address: *merp@epa.gov*.

World wide web (WWW). In addition to being available in the docket, an electronic copy of this proposal will also be available through the WWW. Following the Administrator's signature, a copy of this proposed rule will be posted on the EPA's Inflation Reduction Act

Methane Emissions Reduction Program website at *https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program*.

SUPPLEMENTARY INFORMATION:

Written comments. Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2023-0434, at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA's docket at *https://www.regulations.gov* any information you consider to be confidential business information (CBI), proprietary business information (PBI), or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the web, cloud, or other file sharing system). Commenters who would like the EPA to further consider in this rulemaking comments relevant to this rulemaking that they previously provided on any other rulemaking or request for information (*e.g.*, the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, Docket ID No. EPA-HQ-OAR-2023-0234, the Methane Emissions Reduction Program Request for Information, Docket ID No. EPA-HQ-OAR-2022-0875, and the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Docket ID No. EPA-HQ-OAR-2021-0317) must submit those comments to the EPA during this proposal's comment period. Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI, PBI, or multimedia submissions, and general guidance on making effective comments.

Participation in virtual public hearing. The EPA will begin pre-registering speakers for the hearing no later than one business day after publication in the *Federal Register*. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program* or contact us by email at merp@epa.gov. The last day to pre-register to speak at the hearing will be **[INSERT DATE 12 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. On **[INSERT DATE 14 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**, the EPA will post a general agenda that will list pre-registered speakers in approximate order at *https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program*.

The EPA will make reasonable efforts to follow the schedule as closely as practicable on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to *merp@epa.gov*. The EPA also recommends submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program*. While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact us by email at *merp@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the *Federal Register* announcing updates.

If you require the services of an interpreter or special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by **[INSERT DATE 7 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. The EPA may not be able to arrange accommodations without advanced notice.

Regulated entities. This is a proposed regulation. If finalized, the regulation would affect certain owners or operators of facilities in certain segments of the petroleum and natural gas systems industry that report more than 25,000 metric tons (mt) of carbon dioxide equivalent (CO_2e) pursuant to the requirements codified at 40 CFR part 98, subpart W (Petroleum and Natural Gas Systems) (hereafter referred to as “part 98, subpart W”). Per the requirements of CAA section 136(d), the industry segments to which the waste emissions charge may apply are offshore petroleum and natural gas production, onshore petroleum and natural gas production, onshore natural gas processing, onshore gas transmission compression, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export equipment, onshore petroleum and natural gas gathering and boosting, and onshore natural gas transmission pipeline. Regulated categories and entities include, but are not limited to, those listed in Table 1 of this preamble:

Table 1. Examples of Affected Entities by Category

Category	North American Industry Classification System (NAICS)	Examples of affected facilities
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution facilities.
	211120	Crude petroleum extraction.
	211130	Natural gas extraction.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this proposed action. This table lists the types of facilities that the EPA is now aware could potentially be affected by this action. Other types of facilities than those listed in the table could also be subject to reporting requirements. To determine whether you would be affected by this proposed action, you should carefully examine the applicability criteria found in 40 CFR part 99, subpart A (General Provisions). If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Acronyms and abbreviations. The following acronyms and abbreviations are used in this document.

AMLD	Advanced Mobile Leak Detection
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BOEM	Bureau of Ocean Energy Management
CAA	Clean Air Act
CBI	confidential business information
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
e-GGRT	electronic Greenhouse Gas Reporting Tool
EF	emission factor
EG	emission guidelines
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ET	Eastern time
FAQ	frequently asked question
FR	*Federal Register*
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GOR	gas-to-oil ratio
GRI	Gas Research Institute
GWP	Global Warming Potential
IRA	Inflation Reduction Act of 2022
ICR	Information Collection Request
ISBN	International Standard Book Number
ISO	International Standards Organization

LDC	local distribution company
LNG	liquified natural gas
mmBtu	million British thermal units
MMscf	million standard cubic feet
mt	metric tons
N_2O	nitrous oxide
NAICS	North American Industry Classification System
NGLs	natural gas liquids
NIST	National Institute of Standards and Technology
NSPS	new source performance standards
OEM	original equipment manufacturer
OGI	optical gas imaging
OMB	Office of Management and Budget
PBI	proprietary business information
ppm	parts per million
PRA	Paperwork Reduction Act
RFA	Regulatory Flexibility Act
RY	reporting year
scfh	standard cubic feet per hour
TSD	technical support document
U.S.	United States
UMRA	Unfunded Mandates Reform Act of 1995
UNFCCC	United Nations Framework Convention on Climate Change
VOC	volatile organic compound
WEC	waste emissions charge
WWW	World Wide Web

Table of Contents

I. Background

A. How is this Preamble Organized?

The first section (section I.) of this preamble contains background information regarding the proposed rule. This section also discusses the EPA's legal authority under the Clean Air Act (CAA) to promulgate implementing regulations for the waste emissions charge, proposed to be codified at 40 CFR part 99 (hereafter referred to as "part 99"). Section I. of the preamble also discusses the EPA's legal authority to make confidentiality determinations for new data elements included in waste emissions charge filings (WEC filings) required by the proposed rule. Section II. of this preamble contains detailed information on the proposed provisions necessary to implement CAA section 136(c) through (g), including exemptions. Section III. of this preamble describes the general requirements for the proposed rule. Section IV. of this preamble discusses the proposed confidentiality determinations for new data reporting elements for the proposed part 99 and also discusses confidentiality determinations for two data elements reported under part 98, subpart W. Section V. of this preamble discusses the impacts of the proposed part 99. Section VI. of this preamble describes the statutory and Executive order requirements applicable to this proposed action.

B. Executive Summary

In August 2022, Congress passed, and President Biden signed, the Inflation Reduction Act of 2022 (IRA) into law. Section 60113 of the IRA amended the CAA by adding section 136, "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems." CAA section 136(c) directs the Administrator of the EPA to impose and collect a "Waste Emissions Charge" on methane emissions that exceed statutorily specified waste emissions thresholds from owners or operators of applicable facilities. The waste emissions threshold is a facility-specific amount of metric tons of methane emissions calculated using the segment-specific methane intensity thresholds defined in CAA section 136(f)(1) through (3) and a facility's natural gas throughput (or oil throughput in certain circumstances). Facilities that have methane emissions below the threshold would not be required to pay the charge; facilities that have emissions above the threshold would be required to pay the charge. The waste emissions charge, or WEC, is specified in CAA section 136 to begin for emissions occurring in 2024 at $900 per metric ton of methane exceeding the threshold, increasing to $1,200 per metric ton of methane in 2025, and to $1,500 per metric ton of methane in 2026 and years after. The WEC only applies to the subset of a facility's emissions that are above the waste emissions threshold.

The WEC program applies to facilities that report more than 25,000 mt CO_2e of greenhouse gases emitted per year pursuant to the Greenhouse Gas Reporting Rule's requirements for the petroleum and natural gas systems source category (codified as 40 CFR part 98, subpart W).[1] An applicable facility, as defined in CAA section 136(d), is a facility within the following industry segments (as the following industry segments are defined in part 98, subpart W): onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, onshore gas transmission compression, onshore natural gas transmission pipeline, underground natural gas storage, liquefied natural gas import and export equipment, and liquefied natural gas storage.[2] Congress structured the WEC so that it focuses on high-emitting oil and gas facilities (*i.e.*, those with emissions greater than 25,000 mt CO_2e of greenhouse gases emitted per year and that have a methane emissions intensity in excess of the statutory threshold).

CAA section 136 defines three important elements of the WEC program: 1) waste emissions thresholds; 2) netting of emissions across different facilities; and 3) exemptions for certain emissions and facilities. Facilities may owe a WEC obligation if their subpart W reported emissions exceed facility-specific waste emissions thresholds specified in CAA section 136(f).[3] Facility efficiency in terms of methane emissions per unit of production or throughput would have a large impact on the amount of the WEC owed, with more efficient facilities expected to have emissions falling below the specified thresholds.

Some facilities may have emissions that are below the waste emissions thresholds, and some facilities may have emissions above the thresholds. CAA section 136(f)(4) allows facilities

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[1] 42 U.S.C. 7436(c) (“The Administrator shall impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W of part 98 of title 40, Code of Federal Regulations, regardless of the reporting threshold under that subpart.”).

[2] 42 U.S.C. 7436(d).

[3] 42 U.S.C. 7436(f)(1-3).

under common ownership or control to net emissions across those facilities, which could result in a reduced total charge, or avoidance of the charge.[4]

In addition, there are three exemptions that may lower a facility's WEC or exempt the facility entirely from the charge. The first exemption, found in CAA section 136(f)(5), exempts from the charge emissions occurring at facilities in the onshore or offshore petroleum and natural gas production industry segments that are caused by eligible delays in environmental permitting of gathering or transmission infrastructure.[5] The second exemption, found in CAA section 136(f)(6), exempts from the charge, if certain conditions are met, those facilities that are subject to and in compliance with final methane emissions requirements promulgated pursuant to CAA sections 111(b) and (d).[6] This exemption becomes available only if a determination is made by the Administrator that such final requirements are approved and in effect in all states with respect to the applicable facilities, and that the emissions reductions resulting from those final requirements will achieve equivalent or greater emission reductions as would have resulted from the EPA's proposed methane emissions requirements from 2021.[7] The third exemption, found in CAA section 136(f)(7), exempts from the charge reporting-year emissions from wells that are

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[4] 42 U.S.C. 7436(f)(4) ("In calculating the total emissions charge obligation for facilities under common ownership or control, the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments identified in subsection (d).").

[5] 42 U.S.C. 7436(f)(5). ("Charges shall not be imposed pursuant to paragraph (1) on emissions that exceed the waste emissions threshold specified in such paragraph if such emissions are caused by unreasonable delay, as determined by the Administrator, in environmental permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation.")

[6] 42 U.S.C. 7436(f)(6) ("Charges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 7411 of this title upon a determination by the Administrator that—(i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 7411 of this title have been approved and are in effect in all States with respect to the applicable facilities; and (ii)compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 FR 63110 (November 15, 2021)), if such rule had been finalized and implemented.").

[7] *Id.*

permanently shut in and plugged.[8] In this action, the EPA proposes specific requirements for eligibility for each of these exemptions.

The EPA proposes to require that the WEC would be quantified and paid through a WEC filing submitted no later than March 31 of each calendar year for methane emissions that occurred in the previous calendar year (subpart W reporting year). The WEC filing would include information relevant to calculating the WEC, such as identification of facilities included in netting, eligibility for exemptions from WEC, and supporting information necessary for the EPA to verify information submitted regarding exemptions.

The proposed provisions of part 99 under this rulemaking are described in further detail in sections II. and III. of this preamble.

C. Background and Related Actions

Congress designed the WEC to work in tandem with several related EPA programs. The WEC provides an incentive for the early adoption of methane emission reduction practices and technologies such as those that required under the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (NSPS OOOOb/EG OOOOc), which Congress expected to be promulgated pursuant to CAA section 111. The sooner facilities adopt the methodologies and technologies required in those rules, the lower their assessed WEC; at full implementation of those rules, the EPA expects many of the WEC-affected facilities will be below the WEC emissions thresholds. To further support the overall goal of reducing methane emissions, CAA section 136(a) and (b) also provides $1.55 billion to, among other things, help finance the early adoption of emissions reduction methodologies and technologies and to support monitoring of methane emissions. More detailed background information on the impacts of methane on public

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[8] 42 U.S.C. 7436(f)(7).(“ Charges shall not be imposed with respect to the emissions rate from any well that has been permanently shut-in and plugged in the previous year in accordance with all applicable closure requirements, as determined by the Administrator.”)

health and welfare and the related regulatory activities is provided in section I.C.1. of this preamble.

1. How does methane affect public health and welfare?

Elevated concentrations of greenhouse gases (GHGs) including methane have been warming the planet, leading to changes in the Earth's climate that are occurring at a pace and in a way that threatens human health, society, and the natural environment. While the EPA is not statutorily required to make any particular scientific or factual findings regarding the impact of GHG emissions on public health and welfare in support of the proposed WEC, the EPA is providing in this section a brief scientific background on methane and climate change to offer additional context for this rulemaking and to help the public understand the environmental impacts of GHGs such as methane.

As a GHG, methane in the atmosphere absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change, including increases in air and ocean temperatures, changes in precipitation patterns, retreating snow and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts. Methane also contributes to climate change through chemical reactions in the atmosphere that produce tropospheric ozone and stratospheric water vapor. In 2022, atmospheric concentrations of methane increased by nearly 17 parts per billion (ppb) over 2021 levels to reach 1912 ppb.[9] This was the largest increase since the start of the NOAA atmospheric record in 1984, with current concentrations now more than two and a half times larger than the preindustrial level.[10] Methane is responsible for about one third of all warming resulting from human emissions of well-mixed GHGs,[11] and due to its high radiative efficiency compared to

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[9] NOAA, *https://gml.noaa.gov/webdata/ccgg/trends/ch4/ch4_annmean_gl.txt*.

[10] Blunden, J. and T. Boyer, Eds., 2022: "State of the Climate in 2021." *Bull. Amer. Meteor. Soc.*, 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1*, 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1*

[11] IPCC, 2021: *Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental*

carbon dioxide, methane mitigation is one of the best opportunities for reducing near-term warming.

Major scientific assessments continue to be released that further advance our understanding of the climate system and the impacts that methane and other GHGs have on public health and welfare both for current and future generations. According to the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report, "it is unequivocal that human influence has warmed the atmosphere, ocean and land. Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred."[12] Recent EPA modeling efforts[13] have also shown that impacts from these changes are projected to vary regionally within the U.S. For example, large damages are projected from sea level rise in the Southeast, wildfire smoke in the Western U.S., and impacts to agricultural crops and rail and road infrastructure in the Northern Plains. Scientific assessments, EPA analyses, and updated observations and projections document the rapid rate of current and future climate change and the potential range impacts both globally and in the United States,[14] presenting clear support

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Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 3−32, doi:10.1017/9781009157896.001

[12] *Id.*

[13] (1) EPA. 2021. *Technical Documentation on the Framework for Evaluating Damages and Impacts (FrEDI)*. U.S. Environmental Protection Agency, EPA 430-R-21-004.
(2) Hartin C., E.E. McDuffie, K. Novia, M. Sarofim, B. Parthum, J. Martinich, S. Barr, J. Neumann, J. Willwerth, & A. Fawcett. Advancing the estimation of future climate impacts within the United States. EGUsphere doi: 10.5194/egusphere-2023-114, 2023.

[14] (1) USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018. Available at *https://nca2018.globalchange.gov*.
(2) IPCC, 2021: *Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Pe´an, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekc¸i, R. Yu and B. Zhou (eds.)]. Cambridge University Press.

regarding the current and future dangers of climate change and the importance of GHG emissions mitigation.

2. Related Actions

As mandated by CAA section 136(c) and (d), the applicability of the WEC is based upon the quantity of metric tons of CO_2e emitted per year pursuant to the requirements of subpart W. Further, CAA section 136(e) requires that the WEC amount be calculated based upon methane emissions reported pursuant to subpart W. As a result, this proposed action builds upon previous subpart W rulemakings.

On August 1, 2023, the EPA proposed revisions to subpart W consistent with the authority and directives set forth in CAA section 136(h) as well as the EPA's authority under CAA section 114 (88 FR 50282) (hereafter referred to as the "2023 Subpart W Proposal"). In that rulemaking, the EPA proposed revisions to require reporting of additional emissions or emissions sources to address potential gaps in the total methane emissions reported by facilities to subpart W. For example, these proposed revisions would add a new emissions source, referred to as "other large release events," to capture large emission events that are not accurately accounted for using existing methods in subpart W. The EPA also proposed revisions to add or revise existing calculation methodologies to improve the accuracy of reported emissions, incorporate additional empirical data, and allow owners and operators of applicable facilities to submit empirical emissions data that could appropriately demonstrate the extent to which a charge is owed in implementation of CAA section 136, as directed by CAA section 136(h). The EPA also proposed revisions to existing reporting requirements to collect data that would improve verification of reported data, ensure accurate reporting of emissions, and improve the transparency of reported data. For clarity of discussion within this preamble, unless otherwise stated, references to provisions of subpart W (*i.e.,* 40 CFR 98.230 through 98.238) reflect the language as proposed in the 2023 Subpart W Proposal. The EPA's intention in this proposed rulemaking is that the final WEC rule would update the proposed cross-references to subpart W to be consistent with the final Subpart W rule resulting from the 2023 Subpart W Proposal.

Under the Greenhouse Gas Reporting Program, the EPA also recently issued a supplemental proposal to a 2022 proposed rule (88 FR 32852, May 22, 2023), which included proposed updates to the General Provisions of the Greenhouse Gas Reporting Rule to reflect revised global warming potentials (GWPs), proposed reporting of GHG data from additional sectors (*i.e.*, non-subpart W sectors), and proposed revisions to source categories other than subpart W that would improve implementation of the Greenhouse Gas Reporting Rule. The proposed revision to the GWP of methane (from 25 to 28) is expected to lead to a small increase in the number of facilities that exceed the subpart W 25,000 mt CO_2e threshold and thus become subject to the proposed part 99 requirements. This supplemental proposed rule is not expected to otherwise impact subpart W reporting requirements as they pertain to the applicability or implementation of the proposed part 99 requirements.

In addition, on November 15, 2021 (86 FR 63110), the EPA proposed under CAA section 111(b) standards of performance regulating emissions of methane and volatile organic compounds (VOCs) for certain new, reconstructed, and modified sources in the oil and natural gas source category (proposed as 40 CFR part 60, subpart OOOOb) (hereafter referred to as "NSPS OOOOb"), as well as emissions guidelines regulating emissions of methane under CAA section 111(d) for certain existing oil and natural gas sources (proposed as 40 CFR part 60, subpart OOOOc) (hereafter referred to as "EG OOOOc"). The November 15, 2021 proposal (covering both NSPS OOOOb and EG OOOOc) – and which Congress explicitly referred to in section 136 – will be referred to hereafter as the "NSPS OOOOb/EG OOOOc 2021 Proposal." The NSPS OOOOb/EG OOOOc 2021 Proposal sought to strengthen standards of performance previously in effect under section 111(b) of the CAA for new, modified and reconstructed oil and natural gas sources, and to establish emissions guidelines under section 111(d) of the CAA for states to follow in developing plans to limit methane emissions from existing oil and natural gas sources.

On December 6, 2022, the EPA issued a supplemental proposal to update, strengthen and expand upon the NSPS OOOOb/EG OOOOc 2021 Proposal (87 FR 74702). The December 6, 2022 supplemental proposal will be referred to hereafter as "NSPS OOOOb/EG OOOOc 2022 Supplemental Proposal." This supplemental proposal modified certain standards proposed in the NSPS OOOOb/EG OOOOc 2021 Proposal and added proposed requirements for sources not previously covered. Among other things, the supplemental proposal sought to: ensure that all well sites are routinely monitored for leaks, with requirements based on the type and amount of equipment on site; encourage the deployment of innovative and advanced monitoring technologies by establishing performance requirements that can be met by a broader array of technologies; prevent leaks from abandoned and unplugged wells by requiring documentation that well sites are properly shut-in and plugged before monitoring is allowed to end; leverage qualified expert monitoring to identify "super-emitters" for prompt mitigation; and strengthen requirements for flares.

On December 2, 2023, in an action titled, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," the EPA finalized these two rules to reduce air emissions from the Crude Oil and Natural Gas source category under section 111 of the Clean Air Act. First, the EPA finalized NSPS OOOOb regulating GHG (in the form of a limitation on emissions of methane) and VOCs emissions for the Crude Oil and Natural Gas source category pursuant to CAA section 111(b)(1)(B) (hereafter, "NSPS OOOOb"). Second, the EPA finalized presumptive standards in EG OOOOc to limit GHG emissions (in the form of methane limitations) from designated facilities in the Crude Oil and Natural Gas source category, as well as requirements under the CAA section 111(d) for states to follow in developing, submitting, and implementing state plans to establish performance standards (hereafter, "EG OOOOc").[15]

The NSPS OOOOb/EG OOOOc 2021 Proposal and Final NSPS OOOOb/EG OOOOc are relevant to this WEC proposal in two ways: first, WEC applicable facilities containing CAA section 111(b) and (d) facilities that are in compliance with the applicable standards are likely to have emissions below the thresholds specified in section II.B. of this preamble due to mitigation resulting from meeting the methane emissions requirements of NSPS OOOOb or EG OOOOc-implementing state and Federal plans, and therefore would not be expected to incur charges under the WEC program; and second, compliance with applicable standards (if certain criteria are met) may exempt facilities from the WEC under the regulatory compliance exemption outlined at CAA section 136(f)(6) (discussed in section II.D.2. of this preamble). As a part of the NSPS OOOOb/EG OOOOc 2022 Supplemental Proposal, the EPA requested comment on the criteria and approaches that the Administrator should consider in making the CAA section 136(f)(6)(A)(ii) equivalency determination, which is discussed at section II.D.2. of this preamble.

The EPA also opened a non-regulatory docket on November 4, 2022 and issued a Request for Information (RFI) seeking public input to inform program design related to CAA section 136.[16] As part of this request, the EPA sought input on issues that should be considered related to implementation of the WEC. The comment period closed on January 18, 2023.

The 2023 Subpart W Proposal, the NSPS OOOOb/EG OOOOc 2021 Proposal, the NSPS OOOOb/EG OOOOc 2022 Supplemental Proposal, and the November 2022 request for information are relevant to this proposal. While the EPA has reviewed or will review relevant comments submitted as part of the rulemaking actions and request for information, the EPA is

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[15] In this action, the EPA also finalized several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021, under the CRA, disapproving the 2020 Policy Rule, and also finalized a protocol under the general provisions for use of Optical Gas Imaging.

[16] Docket ID No. EPA-HQ-OAR-2022-0875.

not obligated to respond to those comments in this action since the comment solicitations did not accompany a proposal regarding the WEC. Commenters who would like the EPA to formally consider in this rulemaking any relevant comments previously submitted must resubmit those comments to the EPA during this proposal's comment period.

In addition to the WEC requirement, and the related revisions to subpart W to facilitate accuracy of reporting and charge calculation, as noted in section I.C. of this preamble, CAA sections 136(a) and (b) provide $1.55 billion for the Methane Emissions Reduction Program, including for incentives for methane mitigation and monitoring. The EPA is partnering with the U.S. Department of Energy and National Energy Technology Laboratory to provide financial assistance for monitoring and reducing methane emissions from the oil and gas sector, as well as technical assistance to help implement solutions for monitoring and reducing methane emissions. As designed by Congress, these incentives were intended to complement the regulatory programs and to help facilitate the transition to a more efficient petroleum and natural gas industry.

D. Legal Authority

The EPA is proposing this rule under its newly established authority provided in CAA section 136. As noted in section I.B. of this preamble, the IRA added CAA section 136, "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems," which requires that the EPA impose and collect an annual specified charge on methane emissions that exceed an applicable waste emissions threshold from an owner or operator of an applicable facility that reports more than 25,000 mt CO_2e of greenhouse gases emitted per year pursuant to subpart W of the GHGRP. Under CAA section 136, an "applicable facility" is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution).

The EPA is also proposing elements of this rule under its existing CAA authority provided in CAA section 114, as well as CAA section 301. CAA section 114(a)(1) authorizes the Administrator to require emissions sources, persons subject to the CAA, or persons whom the

Administrator believes may have necessary information to monitor and report emissions and provide other information the Administrator requests for the purposes of carrying out any provision of the CAA (except for a provision of title II with respect to manufacturers of new motor vehicles or new motor vehicle engines). Thus, CAA section 114(a)(1) additionally provides the EPA broad authority to require the information that would be required by this proposed rule because the information is relevant for carrying out CAA section 136. Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations "as are necessary to carry out [its] functions under [the CAA]."

The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA. Section 307(d) contains a set of procedures relating to the issuance and review of certain CAA rules.

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing proposed confidentiality determinations for the new data elements required by this proposed regulation.

II. Requirements to Implement the Waste Emissions Charge

This section summarizes the EPA's proposed approach to calculating WEC, including how WEC would be calculated at the facility level, how netting of emissions from facilities under common ownership or control would be applied, the EPA's interpretation of common ownership or control, and how the exemptions established in CAA section 136(f) would be implemented.

A. Proposed Definitions to Support WEC Implementation

In accordance with CAA section 136(d), applicable facilities under part 99 are those facilities within certain industry segments as defined under part 98, subpart W. Thus, we are proposing several definitions within the general provisions of 40 CFR 99.2. First, as the statute specifies, we are proposing a definition of "applicable facility" to mean a facility within one or more of the following industry segments: onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, onshore natural gas transmission compression, onshore natural gas transmission pipeline, underground natural gas storage, LNG import and export equipment, or LNG storage, as those industry segments are defined in 40 CFR 98.230 of subpart W.[17] A single reporting facility under part 98, subpart W, typically consists of operations within a single industry segment. However, for certain industry segments a single reporting facility may represent operations in two or more industry segments. Industry segments that potentially may exist within the same reporting facility are onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG import and export equipment, and LNG storage. To accommodate for such facilities, we are proposing within the definition of "applicable facility" that such operations would be considered a single applicable facility under part 99.

We are also proposing a definition of "WEC applicable facility" in 40 CFR 99.2, which would mean an applicable facility for which the owner or operator of the subpart W reporting facility reported GHG emissions under subpart W of more than 25,000 mt CO_2e – the amount set in the statute. In cases where a subpart W facility reports under two or more of the industry segments listed in the previous paragraph, the EPA proposes that the 25,000 mt CO_2e threshold would be evaluated based on the total facility GHG emissions reported to subpart W across all of the industry segments (*i.e.*, the facility's total subpart W GHGs). As discussed in section II.B.1. of this preamble, the waste emissions threshold is the facility-specific threshold, based upon an industry segment-specific methane intensity threshold, above which the EPA must impose and collect the WEC. For the purposes of determining the waste emissions threshold for a WEC applicable facility that operates within multiple industry segments, the EPA proposes that each industry segment would be assessed separately (*i.e.*, using industry segment-specific throughput and methane intensity threshold) and then summed together to determine the waste emissions

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[17] *See* 42 U.S.C. 7436(d).

threshold for the facility. The EPA proposes that this approach would be used in all cases where a WEC applicable facility contains equipment in multiple subpart W industry segments.

The EPA requests comment on an alternative definition of WEC applicable facility as it applies to subpart W facilities that report under two or more industry segments. This alternative approach would assess these facilities against the 25,000 mt CO_2e applicability threshold using the CO_2e reported under subpart W for each individual segment at the facility rather than the total facility subpart W CO_2e reported across all segments. CAA section 136(d) defines an applicable facility as one “within” the nine industry segments subject to the WEC and does not specify that an applicable facility is in one and only one industry segment. The EPA understands this to mean that an applicable facility constitutes an entire subpart W facility, including those that report under more than one segment. Thus, based on the statutory text, the EPA proposes to assess WEC applicability based on the entire subpart W facility’s emissions. Based on historic subpart W data, no more than two dozen facilities report data for multiple segments, and when total subpart W CO_2e is summed across all segments at these facilities, almost all of these facilities remain below the 25,000 mt CO_2e threshold. Historic data also show that the industry segments (onshore natural gas processing, onshore natural gas transmission compression, and underground natural gas storage) located at these facilities generally have methane emissions below the waste emissions thresholds. The proposed approach of using total subpart W facility CO_2e for determining WEC applicability therefore would not result in a significant number of facilities being regulated under WEC compared to an approach that assessed applicability using subpart W CO_2e for each individual industry segment at a facility. Based on historic data, the EPA does not expect the very small number of facilities with operations in multiple subpart W segments that could be subject to the WEC under the proposed approach to experience a substantially different financial impact under the alternative approach.

We are also proposing a definition for “WEC applicable emissions” in 40 CFR 99.2, which would mean the annual methane emissions, as calculated using equations specified in part

99, from a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the facility after consideration of any applicable exemptions. The proposed calculation methodology for WEC applicable emissions is addressed in section II.B.2. of this preamble. We are also proposing a definition for "facility applicable emissions" in 40 CFR 99.2 which would mean the annual methane emissions, as calculated using equations specified in part 99, from a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the facility prior to consideration of any applicable exemptions.

The proposed provisions of this part would apply to WEC obligated parties and WEC applicable facilities. In addition to the proposed definition for WEC applicable facility discussed earlier in this section, we are proposing a definition for the term WEC obligated party in 40 CFR 99.2. The term WEC obligated party refers to the owners or operators of one or more WEC applicable facilities. For WEC applicable facilities that have more than one owner or operator, we are proposing that the WEC obligated party is an owner or operator selected by a binding agreement among the owners and operators of the WEC applicable facility. The EPA anticipates that such an agreement would be similar to those used in carrying out 40 CFR 98.4(b) under the GHGRP.

For the purposes of submitting the WEC filing, we are proposing that the WEC obligated party's WEC applicable facilities are the WEC applicable facilities for which it is the owner or operator (including through binding agreement as noted above), as of December 31 of each reporting year. Under the proposed approach, the WEC obligated party would be responsible for any WEC obligation from facilities for which it was the facility owner or operator as of December 31 of the reporting year. The EPA recognizes that facilities may be acquired or divested at any time in the year, and that under the proposed approach the year-end owner or operator would be responsible for data and any corresponding WEC obligation for the entire reporting year. The EPA believes that this approach is both reasonable and necessary for implementation of the WEC program. First, subpart W data reporting uses the same approach;

the facility owner or operator as of December 31 is responsible for emissions for the entire year. Because the subpart W data is inextricably linked to the WEC filing, it would be inappropriate to have different facility owners or operators under each regulation. Specifically, different owners or operators for the same facility under subpart W and the WEC program could lead to challenges for WEC filings and associated data verification, and increase industry burden by requiring significant coordination between different companies. Second, subpart W data are reported on an annual basis, and there is no means by which methane emissions could be accurately allocated across multiple owners or operators in a single year. For example, emissions could not be pro-rated based on time of ownership over the reporting year because emissions do not occur uniformly over time, and emissions from certain sources cannot be linked to specific times. Similarly, there is not a direct relationship between methane emissions and oil and natural gas production, so temporal data on hydrocarbon production could not be used to accurately allocate emissions. The EPA therefore believes it would be neither practical nor accurate for the reporting responsibility and potential WEC obligation for a single facility to be split among multiple WEC obligated parties.

The EPA also recognizes that a facility’s owner or operator, and thus its WEC obligated party, may change between December 31 and March 31. In such situations, under the proposed approach the WEC obligated party associated with a facility as of December 31 would remain responsible for accounting for that facility in its WEC filing and be responsible for any WEC obligation associated with that facility.

The EPA invites comments on these proposed definitions and whether additional definitions would help with the implementation of the WEC. The EPA requests comment on the proposed definition of WEC obligated party being responsible for all facilities for which it was the facility owner or operator as of December 31, regardless of when in the reporting year it became a facility’s owner or operator. The EPA requests comment on alternative definitions of WEC obligated party, including those that would allocate facility subpart W data to multiple

WEC obligated parties and a definition that would place the WEC obligation and reporting requirements on the WEC obligated party that was a facility’s owner or operator at the time of the WEC filing (i.e., as of March 31 of the year following the reporting year rather than December 31 of the reporting year). For alternative definitions that would allocate subpart W data, the EPA requests comment on potential methodologies that would accurately split the annual subpart W data across multiple WEC obligated parties.

B. Waste Emissions Thresholds

The CAA establishes a waste emissions threshold that is defined in terms of industry segment-specific methane intensity thresholds applicable to certain facilities that report GHG emissions under subpart W of the GHGRP. The industry segment-specific methane intensity thresholds specified in CAA 136(f) and listed in Table 2 of this preamble are based on a rate of methane emissions per amount of natural gas or oil sent to sale from or through a facility. The industry segment-specific methane intensity thresholds are generally defined in terms of a percentage of throughput (*e.g.*, 0.002 percent of natural gas sent to sale). However, since the WEC is based on metric tons of methane (*e.g.*, $900/metric ton) that exceed the threshold, for the purposes of calculating the number of metric tons that are subject to the WEC, we are proposing to calculate the facility waste emissions thresholds in metric tons of methane.

For the onshore and offshore petroleum and natural gas production industry segments, CAA section 136(f) differentiates based on whether the facility is sending natural gas to sale or only sending oil to sale, and if the facility does not send natural gas to sale, the threshold is based on methane emissions per amount of oil sent to sale. For facilities that are not in the onshore or offshore production industry segments, the industry segment-specific methane intensity thresholds are based on the amount of natural gas sent to sale from or through the facility. The industry segment-specific methane intensity thresholds are applied to the natural gas or petroleum throughput attributable to that industry segment to calculate facility-specific waste emissions thresholds. See Table 2 for an overview of how the waste emissions thresholds are calculated. Facility waste emissions thresholds are compared to reported methane emissions; facilities with methane emissions that exceed the waste emissions threshold may be subject to the WEC. For WEC applicable facilities under common ownership or control of a single WEC obligated party, the WEC applicable emissions for each facility are summed to calculate the net emissions for that WEC obligated party.

Subpart W requires reporting of natural gas throughput by thousand standard cubic feet, oil by barrels, and methane by metric ton. As a practical matter, since the WEC is based on a dollar per metric ton of methane, the waste emissions thresholds must generally be converted into metric tons of methane for comparison against reported methane, generally by multiplying the thresholds by the density of methane.

Table 2. Industry Segment Throughput Metrics and Methane Intensities

Industry Segment	**Throughput Metric** [a]	**Industry Segment-Specific Methane Intensity**
Onshore petroleum and natural gas production	The quantity of natural gas produced from producing wells that is sent to sale in the calendar year, in thousand standard cubic feet; or the quantity of crude oil produced from producing wells that is sent to sale in the calendar year, in barrels, if facility sends no natural gas to sale	0.20 percent of natural gas sent to sale from facility; or 10 metric tons of methane per million barrels of oil sent to sale from facility, if facility sends no natural gas to sale
Offshore petroleum and natural gas production		
Onshore petroleum and natural gas gathering and boosting	The quantity of natural gas transported through the facility to a downstream endpoint such as a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, a storage facility, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet	0.05 percent of natural gas sent to sale from or through facility
Onshore natural gas processing	The quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year, in thousand standard cubic feet	

Onshore natural gas transmission compression	The quantity of natural gas transported through the compressor station in the calendar year, in thousand standard cubic feet	0.11 percent of natural gas sent to sale from or through facility
Onshore natural gas transmission pipeline	The quantity of natural gas transported through the facility and transferred to third parties such as LDCs or other transmission pipelines in the calendar year, in thousand standard cubic feet	
Underground natural gas storage	The quantity of natural gas withdrawn from storage and sent to sale in the calendar year, in thousand standard cubic feet	
LNG import and export equipment	For LNG import equipment, the quantity of LNG imported that is sent to sale in the calendar year, in thousand standard cubic feet; for LNG export equipment, the quantity of LNG exported that is sent to sale in the calendar year, in thousand standard cubic feet	0.05 percent of natural gas sent to sale from or through facility
LNG storage	The quantity of LNG withdrawn from storage and sent to sale in the calendar year, in thousand standard cubic feet	

[a] Throughput metrics in this table are based on the proposed subpart W reporting elements in the 2023 Subpart W Proposal (88 FR 50282).

1. Facility Waste Emissions Thresholds

CAA section 136(f)(1) through (3) establishes facility-specific waste emissions thresholds above which the EPA must impose and collect the WEC. The CAA defines waste emissions threshold requirements, and establishes the method for calculation of the charge, for nine segments of the oil and gas industry.

CAA section 136(f)(1) requires the EPA to impose and collect the WEC on facilities in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments with methane emissions, in metric tons, that exceed either 0.20 percent of the natural gas sent to sale from the facility or, if no natural gas is sent to sale, 10 metric tons of methane per million barrels of oil sent to sale from the facility. To determine the waste emissions threshold from a WEC applicable facility in the onshore petroleum and natural gas production and the offshore petroleum and natural gas production industry segments, the EPA is proposing two equations based on whether the facility sends natural gas to sale, which reflect the statutory text at 136(f)(1)(A) and (B). For onshore and offshore petroleum and natural gas production WEC applicable facilities that send natural gas to sale, we are proposing to use equation B-1 of 40 CFR 99.20(a). This equation multiplies the annual quantity of natural gas sent to sale from a WEC applicable facility by 0.002 (*i.e.*, 0.20 percent) and the density of methane (0.0192 metric tons per thousand standard cubic feet).[18] For onshore and offshore petroleum and natural gas production facilities that have no natural gas sent to sale, we are proposing to use equation B-2 of 40 CFR 99.20(b). Similar to proposed equation B-2, the annual quantity of oil sent to sale from a WEC applicable facility would be multiplied by 10 metric tons of methane per million barrels of oil. [19]

For WEC applicable facilities in the onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, LNG import and export equipment, and LNG storage industry segments, CAA section 136(f)(2) requires the EPA to impose and collect WEC on facilities with reported methane emissions, in metric tons, that exceed 0.05 percent of the natural gas sent to sale from or through such facility. To determine the waste emissions threshold from a WEC applicable facility in these industry segments, we are proposing to use equation B-3 under 40 CFR 99.20(c). This equation would multiply the annual quantity of natural gas sent to sale from or through a WEC applicable facility by 0.0005 (*i.e.*, 0.05 percent) and the density of methane (0.0192 metric tons per thousand standard cubic feet) to determine the facility-level

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[18] Equation B-1 reflects the statutory text at 136(f)(1)(A), which states: "With respect to imposing and collecting the charge under subsection (c) for an applicable facility [in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments], the Administrator shall impose and collect the charge on the reported metric tons of methane emissions from such facility that exceed (A) 0.20 percent of the natural gas sent to sale from such facility…" 42 U.S.C. 7436(f)(1)(A).

[19] Equation B-2 reflects the statutory text at 136(f)(1)(B), which states: "With respect to imposing and collecting the charge under subsection (c) for an applicable facility [in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments], the Administrator shall impose and collect the charge on the reported metric tons of methane emissions from such facility that exceed… (B) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale." 42 U.S.C. 7436(f)(1)(B).

waste emissions threshold.[20] The EPA notes that certain facilities in the gathering and boosting and natural gas processing industry segments may have zero throughput values using the proposed approach, because these facilities either receive no natural gas, or process or dispose of natural gas received, in a manner that results in sending zero quantities of natural gas to sale. Treatment of these facilities is discussed in section II.B.6. of this preamble.

CAA section 136(f)(3) requires the EPA to impose and collect WEC on WEC applicable facilities in the onshore natural gas transmission compression, onshore natural gas transmission pipeline, and underground natural gas storage industry segments with methane emissions, in metric tons, that exceed 0.11 percent of the natural gas sent to sale from or through such facility. We are proposing that equation B-4 under 40 CFR 99.20(d) be used to calculate the waste emissions threshold from a WEC applicable facility in these industry segments. Using proposed equation B-4 the EPA would multiply the annual quantity of natural gas sent to sale from or through a WEC applicable facility by 0.0011 (*i.e.*, 0.11 percent) and the density of methane (0.0192 metric tons per thousand standard cubic feet) to determine the facility-level waste emissions threshold.[21]

The annual quantity of natural gas sent to sale from or through a facility reported under subpart W is reported in units of thousand standard cubic feet of natural gas per year, while facility methane emissions are reported in metric tons. The EPA is proposing to interpret the industry segment-specific methane intensity thresholds (*i.e.*, 0.20 percent, 0.05 percent, and 0.11

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[20] Equation B-3 reflects the statutory text at 136(f)(2), which states: “With respect to imposing and collecting the charge under subsection (c) for an applicable facility in [the onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, LNG import and export equipment, and LNG storage industry segments], the Administrator shall impose and collect the charge on the reported metric tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facility.” 42 U.S.C. 7436(f)(2).

[21] Equation B-4 reflects the statutory text at 136(f)(3), which states: “With respect to imposing and collecting the charge under subsection (c) for an applicable facility in [the onshore natural gas transmission compression, onshore natural gas transmission pipeline, and underground natural gas storage industry segments], the Administrator shall impose and collect the charge on the reported metric tons of methane emissions that exceed 0.11 percent of the natural gas sent to sale from or through such facility.” 42 U.S.C. 7436(f)(3).

percent) indicated in CAA section 136(f)(1) through (3) to be in units of thousand standard cubic feet of methane of emissions per thousand standard cubic feet of natural gas. This requires reconciliation of methane emissions reported on mass basis and throughput reported on a volumetric basis. Because the waste emission charge is assessed using dollars per metric ton, the amount by which a facility is below or exceeding the waste emissions threshold must ultimately be converted to metric tons. The EPA's proposed approach in equations B-1, B-3, and B-4 calculates facility waste emissions thresholds in metric tons by calculating the volume of gas at the given industry segment-specific methane intensity and then calculating what the mass of that volume would be if it were methane by multiplying by the density of methane (0.0192 metric tons per thousand standard cubic feet at standard temperature and pressure of 60° F and 14.7 psia). This allows the waste emissions threshold to be directly compared to reported metric tons of methane. The proposed approach is mathematically equivalent to, but simpler than, an approach that would convert reported methane emissions to volume, subtract a volumetric waste emissions threshold from that reported volume, and then convert the resulting value back to metric tons methane. The EPA notes that the proposed approach does not require information on the constituents or density of natural gas throughput.

As described in this section of the preamble, we are proposing to calculate waste emissions thresholds at the facility level, using the industry segment-specific methane intensity threshold given in CAA sections 136(f)(1) through (3), and the industry segment throughput reported under part 98, subpart W. The vast majority of facilities report as a single subpart W facility to a single subpart W industry segment. However, as discussed in section II.A. of this preamble, there are a small number of reporters that report as a single subpart W facility to multiple subpart W industry segments. Specifically, for facilities that report to multiple industry segments under a single subpart W facility, we are proposing in 40 CFR 99.20(e) that the facility-level waste emissions threshold is determined as the sum of the waste emissions thresholds for each industry segment that the facility operates within.

The EPA proposes to interpret "natural gas sent to sale" to mean the amount of natural gas sent to sale from a facility in the onshore or offshore petroleum and natural gas industry segments, as reported under subpart W. The EPA proposes to interpret "natural gas sent to sale from or through" to mean the natural gas throughput volume for a facility not in the onshore or offshore petroleum and natural gas industry segments that aligns with the movement of gas through a facility (*e.g.*, gas transported rather than gas received), as reported under subpart W. For facilities in the onshore and offshore petroleum and natural gas production industry segments that do not send natural gas to sale, the EPA proposes to interpret "barrels of oil sent to sale" to mean the quantity of crude oil sent to sale, as reported under subpart W. The EPA is aware of other approaches for calculating "methane intensity" currently in use. These include methodologies that allocate total methane emissions between the petroleum and natural gas value chains and/or use methane rather than natural gas as the throughput value. CAA section 136(f)(1) through (3) refers to reported facility emissions and does not discuss allocation of emissions between petroleum and natural gas. With the exception of production facilities that only produce oil, the statutory text clearly lists natural gas as the throughput value. Further, the proposed approach can be implemented with data currently reported under subpart W, while alternative methane intensity methodologies would require reporting of additional data and increase the burden on the oil and gas industry. For example, an approach that calculates intensity as methane emissions divided by the methane in natural gas throughput would require facilities to collect and report additional information of the methane content of natural gas. An approach that calculates methane intensity as the mass of methane emissions divided by the mass of natural gas would require facilities to collect and report detailed information on all of the constituents of natural gas throughput. Finally, an approach that allocates methane emissions between the petroleum and natural gas value chains based on energy content would require facilities to collect and report detailed data on the constituents and energy content of all hydrocarbon throughput. The EPA therefore believes that the proposed approaches not only follow a plain reading of CAA section 136(f) but are also the best and most reasonable approaches.

The EPA invites comments on our proposed approach for calculating the waste emissions thresholds, particularly our proposed methodology and the underlying assumptions used to calculate the waste emissions threshold in metric tons of methane.

2. Facility Methane Emissions

To determine the total methane emissions from a WEC applicable facility, the EPA proposes to use facility-level methane data as reported under subpart W. On August 1, 2023, the EPA proposed revisions to subpart W consistent with the authority and directives set forth in CAA section 136(h) as well as the EPA's authority under CAA section 114 (88 FR 50282). Facility methane emissions (and any emissions associated with exemptions from the WEC) would be calculated using methods and data required by subpart W for the emissions year covered by the annual WEC filing. For example, for the first year of the WEC (2024 emissions), WEC calculations would be based on the Subpart W requirements effective in 2024, and emissions year 2025 emissions and beyond would be based on Subpart W requirements effective in 2025 or any future revisions. The proposed approaches for calculating waste emissions thresholds and facility methane emissions align with the text of CAA section 136(f). CAA section 136(f)(1) through (3) states that the WEC is to be calculated based "on the reported metric tons of methane emissions from such facility that exceed" specified percentages of the "natural gas sent to sale from such facility" or "natural gas sent to sale from or through such facility" (or for onshore and offshore petroleum facilities that do not send gas to sale, "ten metric tons of methane per million barrels of oil sent to sale from such facility"). The EPA proposes to interpret "reported metric tons of methane emissions" to mean all reported methane emissions from a facility, as reported under subpart W. This value is an input to equation B-6.

3. Facility WEC Calculation

To calculate the amount by which a WEC applicable facility is below or exceeding the waste emissions threshold, the EPA proposes to use equation B-6 of 40 CFR 99.21, in which the facility waste emissions threshold, as determined in 40 CFR 99.20, is subtracted from facility total methane emissions. This calculation results in a value of metric tons of methane, the total facility applicable emissions, that is negative for facilities below the waste emissions threshold and positive for facilities exceeding the waste emissions threshold. The remainder of proposed 40 CFR 99.21 describes how to determine the WEC applicable emissions below or exceeding the waste emissions threshold considering any exemptions that may apply for WEC applicable facilities with total facility applicable emissions greater than 0 mt CH_4 (see section II.D. of this preamble for more information on the exemptions). As discussed in section II.C.2.b. of this preamble, the EPA proposes that WEC applicable facilities receiving the regulatory compliance exemption would be exempted from the WEC, and therefore would have zero WEC applicable emissions. For facilities in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments with total facility applicable emissions greater than 0 mt CH_4, any methane emissions associated with applicable exemptions would be subtracted to calculate WEC applicable emissions. For all other facilities, facility applicable emissions would equal WEC applicable emissions (unless the facility was receiving the regulatory compliance exemption).

The EPA invites comments on the proposed approach for calculating WEC applicable emissions.

4. Netting

The metric tons of methane emissions equal to, below, or exceeding the waste emissions threshold, or WEC applicable emissions, for each WEC applicable facility would be determined as specified in 40 CFR 99.21. CAA section 136(f)(4) allows for the netting of emissions at facilities below the waste emissions thresholds with emissions at facilities exceeding the waste emissions thresholds for facilities under common ownership or control within and across all applicable industry segments identified in 136(d). The EPA proposes to implement netting using equation B-8 at 40 CFR 99.22. Equation B-8 would sum the WEC applicable emissions from all WEC applicable facilities under the common ownership of control of a WEC obligated party to calculate net WEC emissions for that WEC obligated party. The EPA's proposed interpretation of common ownership and control and definition of WEC obligated party are discussed in section II.C. of this preamble.

5. Waste Emissions Charge Calculation

CAA section 136(e) establishes annual $/metric ton charges for all methane emissions from WEC applicable facilities exceeding the waste emissions thresholds. The EPA proposes that a WEC obligated party's total annual WEC, or WEC obligation, would be calculated by multiplying its net WEC emissions, as determined by proposed Equation B-8, by the annual $/metric ton charge. WEC obligated parties with net WEC emissions less than or equal to zero would not have a WEC obligation. WEC obligated parties with net WEC emissions greater than zero would have a WEC obligation and be required to pay a waste emissions charge. WEC obligation calculations would be made for calendar years 2024, 2025, 2026, and each year thereafter as per proposed 40 CFR 99.23.

6. Gathering and Boosting and Processing Facilities with Zero Reported Throughput

The EPA is aware of a small number of gathering and boosting and natural gas processing facilities that emit methane and report under subpart W, but do not send gas to sale. As a result, these facilities would report zero natural gas volumes for the throughput metrics used in the proposed waste emissions threshold calculations. For the gathering and boosting industry segment, these may be facilities that receive natural gas but then reinject it underground or otherwise do not transport any natural gas. For the processing industry segment, these may be fractionation plants that only receive and process natural gas liquids (NGLs) and do not handle natural gas. Under the proposed approach, all reported methane emissions from facilities with no reported throughput would be considered to be exceeding the waste emissions threshold. The EPA notes that the proposed approach is based on a plain reading of the statutory text; because these facilities would have a calculated waste emissions threshold of zero, all reported methane would by default be exceeding the threshold. The EPA requests comment on the treatment of gathering and boosting and natural gas processing facilities that do not report any volumes for the proposed WEC throughput metrics. The EPA requests comment on the proposed approach that would consider all reported methane from these facilities to be above the waste emissions threshold. The EPA also requests comment on an alternative approach that would consider all reported methane emissions from these facilities to be below the waste emissions threshold.

C. Common Ownership or Control for Netting of Emissions

1. EPA Interpretation and Proposal to Implement "Common Ownership or Control" for the Purposes of Part 99

CAA section 136(f)(4) allows WEC applicable facilities under "common ownership or control" to net "emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments" listed in section 136(d) and as defined in subpart W. The EPA interprets this to mean that for all eligible WEC applicable facilities under common ownership or control, the amount of metric tons of methane below the waste emissions thresholds (*i.e.*, the difference between emissions equal to the waste emissions threshold and reported emissions) at facilities below the waste emissions threshold may be used to net against the amount of metric tons of methane emissions that exceed the waste emissions thresholds at facilities above the waste emissions threshold. For the purposes of establishing common ownership or control under CAA section 136(f)(4), the EPA proposes to define "WEC obligated party" in 40 CFR 99.2. The EPA proposes that each subpart W facility would be associated with a single WEC obligated party (though each WEC obligated party may be associated with multiple subpart W facilities), which would be reported under the proposed requirements at 40 CFR 99.7. As discussed in section II.B.4. of this preamble and proposed in 40

CFR 99.22, all WEC applicable facilities associated with a common WEC obligated party would be able to net emissions for the purposes of calculating the WEC obligated party's net emissions and total WEC obligation.

The EPA proposes that the WEC obligated party be the subpart W facility "owner or operator" as reported under 40 CFR 98.4(i)(3). The EPA proposes definitions for facility "owner" and "operator" that are applicable to the offshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG import and export equipment, and LNG storage industry segments at 40 CFR 99.2. The onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and onshore natural gas transmission pipeline industry segments each have separate definitions for facility "owner or operator" proposed at 40 CFR 99.2. These proposed definitions are identical to the corresponding definitions in 40 CFR part 98; the EPA proposes that the owner or operator associated with a subpart W facility as reported under 40 CFR 98.4(i)(3) (regarding the list of owners or operators of the facility for the certification of representation of the designated representative) would also be the WEC obligated party for that facility. The EPA believes that the proposed approach for using facility owner or operator for the purpose of defining common ownership or control aligns with a plain reading of the statutory text. CAA section 136(c) states that a charge on methane emissions that exceed the waste emissions threshold shall be imposed and collected "from an owner or operator of an applicable facility." Further, in the context of required revisions to the subpart W methodologies used to calculate methane emissions, CAA section 136(h) states that those revisions must be made to "allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed." Thus, CAA section 136(c) requires the charge to be imposed and collected on a facility owner or operator, and CAA section 136(h) presumes that owners and operators are responsible for submitting empirical data. Furthermore, since the list of owners or operators for each facility is directly reported under 40 CFR 98.4(i)(3), an established program at the time that Congress drafted CAA section 136, the EPA proposes that under the best reading of the statutory text, the facility owner or operator would be used as the entity for establishing common ownership or control of subpart W facilities within and across all applicable subpart W industry segments.

Although the EPA believes that the owner or operator approach is the most appropriate for netting under WEC, we seek comment on an alternative approach that would use the parent company of a facility's owner or operator for the WEC obligated party and determining common ownership or control of facilities. For each subpart W facility, the facility owner or operator and parent company are reported under 40 CFR 98.4(i)(3) and 40 CFR 98.3(c)(11), respectively. The parent company represents the highest-level company based in the United States with an ownership interest in the facility. For parent company reporting, the percent ownership in the facility is also reported under 40 CFR 98.3(c)(11). Because a parent company has an ownership interest in a subpart W facility, multiple facilities may be said to be owned by the same parent company and might also be considered as being under common ownership or control of that parent company. So, one difference between using the owner or operator rather than a parent company for establishing common ownership or control is the number of facilities that may be brought under common ownership or control in each approach. For most facilities, the reported owner or operator is a subsidiary of the reported parent company. A single parent company may have multiple different owners or operators (*i.e.*, subsidiaries) associated with facilities within and across subpart W industry segments. For example, an onshore petroleum and natural gas production facility and onshore natural gas processing facility owned by the same parent company may each have a different owner or operator. The number of "common" facilities is usually higher when the parent company is used, and lower when the owner or operator is used. The parent company approach would therefore provide a broader interpretation of common ownership or control relative to use of owner or operator. However, it is important to note that at the time CAA section 136 was enacted in 2022, the term "common ownership or common control" was a term used in the subpart W regulations. Under the subpart W regulations, the EPA has used the term "common ownership or control" to refer to the owner or operator, not to the parent company. Congress was likely aware of this definition when it enacted section 136. Therefore, the EPA is proposing to use facility owner or operator for the purpose of establishing common ownership or control based on a plain reading of CAA section 136(c), and believes that this is the better reading of the text in context with subpart W. However, the EPA requests comment on both the proposed approach using facility owner or operator and on an alternative approach using facility parent company for determining common ownership or control of WEC applicable facilities.

In some cases, a WEC applicable facility may have multiple owners or operators reported under 40 CFR 98.4(i)(3). In these situations, the EPA proposes that the facility owners or operators would designate one of the owners or operators as the WEC obligated party for that facility, as proposed in 40 CFR 99.4. Under the proposed approach, the process for selection of the WEC obligated party at facilities with multiple owners or operators would be similar to the approach for selecting a designated representative under 40 CFR part 98. This process would require selection of a single WEC obligated party for the facility by an agreement binding on each of the owners or operators associated with the facility. The proposed approach for facilities with multiple owners allocates all facility-level methane emissions below or exceeding the waste emissions thresholds to a single WEC obligated party. We request comment on the proposed approach of allocating all methane emissions below or exceeding the waste emissions thresholds from a facility with multiple owners or operators to a single WEC obligated party. We request comment on other approaches that could be used to allocate emissions to owners or operators at facilities with multiple owners or operators. We request comment on the proposed approach of requiring the group of facility owners or operators to determine which owner or operator is the

WEC obligated party, and alternative approaches for designating the WEC obligated party, at facilities with multiple owners or operators.

The EPA also evaluated an approach that would allocate facility methane emissions below or exceeding the waste emissions thresholds at facilities with multiple owners to parent companies based on their reported percent ownership in the facility. Some subpart W facilities with multiple owners have parent companies with very small (*i.e.*, less than one percent) equity shares. The minority owners may include individuals and small oil and gas companies with no operational control over the facility. Allocating methane emissions below or exceeding the waste emissions thresholds based on facility ownership would expose a larger number of individuals and small companies to potential WEC obligations. We note that allocating methane emissions from facilities with multiple owners to each owner based on facility ownership would only be possible using a parent company approach and not using the proposed owner or operator approach because GHGRP reporting does not currently include data on owner or operator facility equity share or include direct linkages between owners or operators and parent companies that could be used to assign facility ownership percentages to owners or operators. There may also be situations in which the facility owner or operator is a third-party operator with no ownership in the facility either directly or through their parent company.

We request comment on an alternate approach that would allocate methane emissions to parent companies using percent ownership in the facility as well as other possible allocation methodologies for facilities with multiple parent companies. We request comment relevant to understanding other appropriate approaches for allocating emissions from a facility with multiple parent companies or owners or operators to a single WEC obligated party or multiple WEC obligated parties. For example, how are costs allocated at such facilities, and are they usually shared by parent companies (*e.g.*, based on percent ownership in the facility), entirely borne by the facility operator, or does cost sharing vary based on facility-specific contractual agreements?

2. Facilities Eligible for the Netting of Emissions

The EPA's proposed implementation of CAA section 136(f)(4) would define which types of applicable subpart W facilities are eligible to net emissions. We propose to establish netting eligibility criteria based on a facility's total reported subpart W GHG emissions, status in relation to the regulatory compliance exemption, and overall regulated status under the GHGRP. In our proposed approach to netting, we chose interpretations which were the most consistent with a plain reading of the CAA, as well as the most transparent and straightforward to implement. As described in more detail in the following sections, our approach assumes that if a facility's emissions are not subject to the WEC, either because the facility is not a WEC applicable facility, or because a WEC applicable facility receives the regulatory compliance exemption, that facility's emissions do not factor into the netting of emissions for a WEC obligated party. In other words, only WEC applicable facilities may net, and only WEC applicable emissions may be netted. As will be explained further in section II.C.2.a. of this preamble, we believe this interpretation is consistent with CAA section 136(f)(4) "the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments identified in subsection (d)," since the reference to "applicable thresholds" and "applicable segments", which reflect other subsections under CAA section 136, implies that only WEC applicable emissions should be considered in the netting calculation. We note that for applicable facilities with unreasonable delay or plugged well exemptions, under the proposal, emissions associated with these exemptions would be removed from any emissions exceeding the waste emissions threshold prior to netting calculations.

a. Facilities Required to Report to GHGRP and That Have Subpart W Emissions Greater Than 25,000 Metric Tons of CO_2e

In accordance with CAA section 136(c) and the proposed definition of "WEC applicable facility" in 40 CFR 99.2, we are proposing that subpart W facilities that have subpart W emissions greater than 25,000 mt CO_2e are eligible for netting, with the exception of those that are receiving the regulatory compliance exemption (as discussed in section II.D.2. of this preamble). Facilities that report less than 25,000 mt CO_2e under subpart W are not subject to the WEC, and the EPA proposes that such facilities would not be eligible for netting. These types of facilities are discussed in greater detail in section II.C.2.c. of this preamble. The EPA's proposed approach follows what the agency considers to be the best reading of the plain text of, and the relationship between CAA sections 136(d), 136(c), and 136(f) (which includes subsections 136(f)(4) and 136(f)(1)-(3)). The following sections will provide an overview of the relevant statutory text, and the corresponding basis for the EPA's belief that only WEC applicable facilities may net, and only WEC obligated emissions may be netted, under CAA section 136(f)(4).

CAA section 136(d) introduces the nine industry segments within which all subpart W facilities must fall in order to be evaluated for WEC applicability. Importantly, facilities within these segments are "applicable facilities", per CAA section 136(d), but they are not necessarily "WEC applicable facilities", subject to possible WEC obligation, unless they report over 25,000 mt CO_2e per year under subpart W. CAA section 136(c) clarifies this point. Specifically, CAA section 136(c) requires the Administrator to impose and collect a charge on the owner or operator "of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W". Thus, building upon the CAA section 136(d) definition, CAA section 136(c) establishes that only facilities which both fall within one or more of the nine CAA section 136(d) industry segments *and* report more than 25,000 mt CO_2e under subpart W are subject to the WEC program. For clarity, in this rulemaking the EPA refers to these facilities as "WEC applicable facilities".

CAA section 136(f), which is entitled "Waste Emissions Threshold", includes a series of subsections under this heading. Subsections 136(f)(1)-(3) illustrate the meaning of "waste emissions threshold" in this context, and explain that these are actually a series of thresholds which determine when and how to impose a charge on methane emissions from WEC applicable facilities, depending on which industry segment or segments they fall under. Specifically, the nine CAA section 136(d) industry segments are categorized into four groups, and a waste emissions threshold is applied to each of the four. CAA section 136(f)(1) covers offshore and onshore petroleum and natural gas production (industry segments (1) and (2) under CAA section 136(d)), and further divides this category depending on whether or not natural gas is sent to sale: "With respect to imposing and collecting the charge under subsection (c) for an applicable facility in an industry segment listed in paragraph (1) or (2) of subsection (d), the Administrator shall impose and collect the charge on the reported metric tons of methane emissions from such facility that exceed (A) 0.20 percent of the natural gas sent to sale from such facility; or (B) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale."[22]

CAA sections 136(f)(2) and (3) follow the same model: section 136(f)(2) establishes thresholds for nonproduction petroleum and natural gas systems (industry segments (3), (6), (7), and (8) under section 136(d)[23]), and imposes a charge on "the reported metric tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facility"[24]; and section 136(f)(3) establishes thresholds for natural gas transmission (industry segments (4), (5), and (9)[25]) and imposes a charge on "the reported metric tons of methane emissions that exceed 0.11 percent of the natural gas sent to sale from or through such facility."[26] But each industry-specific threshold is introduced in the same way: "With respect to *imposing and collecting the charge under subsection (c) for an applicable facility in an industry segment listed*

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[22] 42 U.S.C. at 7436(f)(1).

[23] Specifically: (3) onshore natural gas processing; (6) liquefied natural gas storage; (7) liquefied natural gas import and export equipment; and (8) onshore petroleum and natural gas gathering and boosting.

[24] *Id.* at section 7436(f)(2).

[25] Specifically, (4) onshore natural gas transmission compression; (5) underground natural gas storage; and (9) onshore natural gas transmission.

[26] *Id.* at section 7436(f)(3).

in paragraph (x) of subsection (d), [charges shall be imposed as follows]". Following this plain text, it is clear that the CAA section 136(f) waste emission thresholds apply *only to WEC applicable facilities* – that is, facilities within one or more of the nine WEC industry segments listed in CAA section 136(d) which emit more than 25,000 mt per year CO_2e under subpart W, and thus may be subject to charge under CAA section 136(c).

Finally, in the netting provision itself, CAA section 136(f)(4), states that "in calculating the total emissions charge obligation for facilities under common ownership or control, the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments identified in subsection (d)". As noted above, the EPA is proposing that this netting provision applies to WEC applicable facilities and WEC applicable emissions only, for three compelling reasons.

First, the EPA believes that per the best reading of the statute, the term "applicable thresholds" refers to the waste emission thresholds outlined in CAA section 136(f)(1)-(3). This is important because, as noted above, the waste emissions thresholds apply *only* to WEC applicable facilities – they determine whether, and how, a charge shall be imposed on methane emissions from a facility which has already been triggered into the WEC program by virtue of its 25,000 mt per year CO_2e in subpart W. The thresholds do not apply to facilities which emit fewer than 25,000 mt per year of CO_2e under subpart W, because under CAA section136(c), no charge may be imposed or collected on such facilities. Facilities which emit less than 25,000 mt per year of CO_2e under subpart W may emit any amount of methane, but these methane emissions are not WEC applicable emissions: they cannot be evaluated according to the waste emissions thresholds, and they cannot be considered to fall either above or below these thresholds. Thus, in "*account[ing] for facility emissions levels that are below the applicable thresholds*", the EPA understands that it must account for WEC applicable emissions from WEC applicable facilities which fall below the waste emissions thresholds, and produce a negative value under Equation B-6 (see above at section II.B.3.).

As previously stated, EPA's conclusion that the term "applicable thresholds" in CAA section 136(f)(4) refers to the waste emissions thresholds outlined in CAA section 136(f)(1)-(3) is supported by both the text and structure of the statute. First, the structure of the statute strongly supports the presumption that CAA section 136(f)(4) refers to netting based on a facility's relationship to the waste emissions thresholds because CAA section 136(f)(4) appears as part of CAA section 136(f), under the "waste emissions threshold" heading, and immediately following CAA section 136(f)(1)-(3)'s establishment of the specific waste emissions thresholds for each industry segment. It follows that CAA section 136(f)(4)'s reference to "applicable thresholds" refers to these industry segment-specific requirements, and accordingly "applicable segments" refers to the industry segments identified in CAA section 136(f)(1)-(3).

A close reading of the text also strongly supports our presumption regarding the waste emissions thresholds, because CAA section 136(f)(4) refers to facility emissions levels that are "below the *applicable thresholds*," plural. The use of the plural, and the use of the term "applicable," both indicate that Congress was referring here to the multiple waste emissions thresholds introduced in CAA sections 136(f)(1) through (3), which specifically and separately apply to WEC applicable facilities within various subsets of industry segments, defined in CAA section 136(d). Again, these separate thresholds *only* apply to WEC applicable facilities, which emit over 25,000 tons per year of CO_2e per year.

In addition to the "applicable thresholds" question, the EPA believes that Congress's use of the term "applicable segments" in stating that EPA may "redu[ce] the total obligation to account for facility emissions levels that are below the applicable thresholds *within and across all applicable segments identified in subsection (d)*," is significant here. While CAA section 136(d) introduces the nine relevant "industry segments" within which all WEC applicable facilities must fall, CAA section 136(f)(4) classes these segments into four groups, and is the only provision to use the term “applicable segments”. As noted above, CAA section 136(f) establishes a set of requirements determining when and how to impose a charge on those facilities triggered into the program, depending on their industry segment and the amount of methane they emit. It follows that CAA section 136(f)(4)’s reference to “applicable thresholds” refers to these four group-specific thresholds, and “applicable segments” refers to the nine segments within the four segment groups. In other words, each group of segments constitutes the “applicable” segments to their corresponding applicable threshold. This is important, again because the four groups laid out under CAA section 136(f) include only WEC applicable facilities.

Finally, Congress’s statement that netting shall be employed “in calculating the total emissions charge obligation for facilities under common ownership or control”, further indicates that only WEC applicable facilities may be netted. Logic indicates that only WEC applicable facilities, with WEC applicable emissions, would be relevant to a determination of total emissions charge obligation. As regards the WEC program, WEC obligated parties are concerned with methane emissions for the WEC applicable facilities for which they are responsible – not various other subpart W facilities for which a WEC charge can never be imposed. Accordingly, the EPA believes that under the best reading of this provision WEC obligated parties may net WEC applicable methane emissions between facilities in different segments, as long as all facilities are WEC applicable facilities.

b. Facilities With Subpart W Emissions Greater Than 25,000 Metric Tons of CO_2e That Are Receiving the Regulatory Compliance Exemption

The EPA proposes that during such time that a facility receives the regulatory compliance exemption, that facility would have zero WEC applicable emissions and thus would not be able to participate in the netting of methane emissions across facilities under common ownership or control of a WEC obligated party. The EPA’s proposed approach is based on a plain reading of the statutory text, and follows the same reasoning outlined in section II.C.2.a. of this preamble, which explains that under the best reading of the text, only WEC applicable facilities may net.. This section will further expand upon EPA reasoning that only WEC applicable emissions may be netted, and clarify this point for purposes of the regulatory compliance exemption.

CAA section 136(f)(6)(A) states that "[c]harges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111" if specific criteria are met (these criteria are discussed in section II.D.2. of this preamble). The EPA's interpretation of the regulatory compliance exemption is that, for a WEC applicable facility meeting the exemption criteria, the entire facility is exempted, and therefore the facility does not generate WEC-applicable emissions. In order to net, facilities must be WEC applicable facilities (they must emit over 25,000 CO_2e per year under subpart W) and they must also generate WEC applicable emissions (methane emissions below or above the WEC emissions thresholds *that are subject to charge*.) Again, this follows from the text. Section 136(f)(4) applies "in calculating the total emissions charge obligation" only. Emissions which are subject to an exemption are by definition not subject to charge. WEC applicable emissions are only those emissions subject to charge under section 136(c). Because, under the proposed approach WEC applicable facilities with the regulatory compliance exemption would have zero WEC applicable emissions, these facilities would by default not be able to participate in netting (*i.e.*, they would have no emissions to net). The proposed approach of facilities with the regulatory compliance exemption having zero WEC applicable emissions allows for the practical implementation of the exemption within the broader framework of the proposed WEC calculations. Assigning exempted facilities zero WEC applicable emissions ensures that charges shall not be imposed on these facilities without interfering with netting calculations or removing facility-specific reporting elements necessary for WEC implementation. Such facilities would continue to be included in WEC filings reported under part 99 as long as they remain WEC applicable facilities. Further, if such facilities fall out of compliance such that the regulatory compliance exemption no longer applies and they again generate WEC applicable emissions, such facilities would again be included in netting.

The EPA notes that under the proposed approach, facilities with emissions below the waste emissions threshold would not receive the regulatory compliance exemption (see discussion in section II.D.2.f. of this preamble), and thus these facilities would always have WEC applicable emissions and would be able to participate in netting across facilities under common ownership or control.

The EPA requests comment on the proposed approach in which WEC applicable facilities receiving the regulatory compliance exemption would have zero WEC applicable emissions. The EPA requests comment on other options for WEC applicable facilities receiving the regulatory compliance exemption and their treatment in the context of netting.

c. Exclusion of Facilities Reporting 25,000 or Fewer Metric Tons of CO_2e to Subpart W of Part 98

Per CAA section 136(c), the WEC shall only be imposed on owners or operators of applicable facilities that report more than 25,000 mt CO_2e under subpart W. A large number of facilities that report under the GHGRP have subpart W emissions below 25,000 mt CO_2e. A part 98 subpart W facility is generally allowed to cease reporting or "offramp" due to meeting either the 15,000 mt CO_2e level or the 25,000 mt CO_2e level for the number of years specified in 40 CFR 98.2(i) based on the CO_2e reported, as calculated in accordance with 40 CFR 98.3(c)(4)(i) (*i.e.*, the annual emissions report value as specified in that provision). Some facilities have dropped below 25,000 mt CO_2e in total reported emissions to part 98 and are continuing to report while on the reporting offramp. Other facilities report emissions under multiple subparts (*e.g.*, subpart W and subpart C) and have total emissions equal to or greater than 25,000 mt CO_2e across both subparts, but subpart W emissions below 25,000 mt CO_2e. The latter category includes processing plants, transmission compressor stations, underground storage facilities, LNG storage facilities, and LNG import and export facilities that report their combustion emissions under subpart C. Many of these facilities have total GHGRP emissions exceeding 25,000 mt CO_2e, but subpart W emissions that alone fall below this threshold.

We are proposing that subpart W facilities with subpart W emissions equal to or below 25,000 mt CO_2e are not WEC applicable facilities and are therefore excluded from netting. This proposed approach aligns with a plain reading of the requirement in CAA section 136(c) that only applicable facilities with subpart W emissions exceeding 25,000 mt CO_2e are subject to the WEC – facilities below this threshold are not subject to the WEC and therefore do not generate WEC applicable emissions and are not able to net emissions.

d. Exclusion of Facilities Not Required to Report to the GHGRP

Per CAA section 136(c) and (d), CAA section 136(f)(4), and the proposed definition of "WEC Applicable Facility" in 40 CFR 99.2, which reflects the statutory text at CAA section 136(d), we are proposing that facilities that are not required to report to the GHGRP, and thus are not WEC applicable facilities, would not be eligible for netting. Again following the reasoning outlined in section II.C.2.a. of this preamble, the EPA's proposed approach is based on a plain reading of CAA section 136(f)(4), which states that netting is allowed within and across the nine subpart W industry segments identified in CAA section 136(d); section 136(d), which states that "applicable facility(ies)" are facilities within industry segments "as defined in subpart W"; and section 136(c), which states that the WEC is only applicable to subpart W facilities that report more than 25,000 CO_2e per year. Following the plain text, only facilities subject to subpart W may be evaluated as possible WEC applicable facilities, and only WEC applicable facilities (subpart W facilities emitting over 25,000 CO_2e) can have WEC applicable emissions that may be subject to charge. As explained in section II.C.2.a. of this preamble, only WEC applicable facilities may net, and only WEC applicable emissions may be netted. Further, CAA section 136(c) states that the WEC is only applicable to certain facilities that report under subpart W of the GHGRP.

D. Exemptions to the Waste Emissions Charge

1. Exemption for Emissions From Eligible Delays in Environmental Permitting Under CAA Section 136(f)(5)

CAA section 136(f)(5) establishes an exemption for emissions resulting from delay in environmental permitting by stating, “Charges shall not be imposed pursuant to paragraph (1) on emissions that exceed the waste emissions threshold specified in such paragraph if such emissions are caused by unreasonable delay, as determined by the Administrator, in environmental permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation.”

This provision would exempt from the charge certain emissions occurring at facilities in the onshore and offshore production segments. Paragraph (1) referenced in the exemption refers to CAA section 136(f)(1), which establishes the waste emissions threshold for applicable facilities in the production sector, as discussed in section II.B. of this preamble. The exemption is limited to emissions occurring as a result of certain delays in permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation. Infrastructure necessary for offtake would include gathering and transmission pipelines and compressor stations. Increased volume as a result of methane emissions mitigation implementation would include increased natural gas amounts available for transport that would have otherwise been emitted.

a. Emissions Eligible for the Permitting Delay Exemption

Given the complexity of defining and determining “unreasonable delay” related to environmental permitting, the EPA is proposing a simplified approach of establishing a set of four criteria for applying the unreasonable delay exemption established by CAA section 136(f)(5). These criteria would only apply in the context of determining eligible emission exemptions for the implementation of CAA 136(f)(5) and this proposed rulemaking; they are not intended to speak to the reasonableness of a permitting delay in any other context. The EPA understands that the issue of what constitutes an unreasonable delay is multi-faceted and may be quite different under different factual circumstances. At the same time, the EPA believes it is important in the context of this program to propose a definition that is both consistent with the statutory charge and administrable within the capabilities of the EPA. With those caveats in mind, the EPA proposes the following four criteria for implementing this exemption: (1) the facility must have emissions that exceed the waste emissions threshold; (2) neither the entity seeking the exemption, nor the entity responsible for seeking the permit, may have contributed to the delay; (3) the exempted emissions must be those (and only those) resulting from the flaring of gas that would have been mitigated without the permit delay, and the flaring that occurs must be in compliance with all applicable local, state, and Federal regulations regarding flaring emissions; and (4) a set period of months must have passed from the time a submitted permit application was determined to be complete by the applicable permitting authority.

The EPA believes this approach meets the Congressional intent of this exemption while creating a program that can be implemented annually allowing for collection of WEC in a timely manner. The proposed approach is intended to reduce burden on the companies and government compared with an approach that would not specify a timeframe or other criteria but would rely on decisions made on a case-by-case basis to determine whether the timing and other circumstances of an individual permitting action constitutes an unreasonable delay. We note, however, that these criteria outlined above, including the timeframe, are proposed for the purpose of defining the emissions eligible for an exemption for the purposes of the implementation of CAA 136(f)(5) and this proposed rulemaking only and are not applicable for defining an unreasonable delay outside of this context. The criteria introduced in this section do not apply to the determination of unreasonable delay for purposes of the National Environmental Policy Act (NEPA), the Administrative Procedure Act (APA), or any other law involved in permitting processes or any other agency actions. In particular, the timeline criterion should not be considered applicable or informative to the determination of unreasonable delay in any context other than determining emission exemptions for the implementation of CAA 136(f)(5) and this proposed rulemaking.

The first criterion, that the facility must have emissions that exceed the waste emissions threshold, is based on CAA 136(f)(5), which states that “charges shall not be imposed pursuant to paragraph (1) on emissions that exceed the waste emissions threshold specified in such paragraph if such emissions are caused by unreasonable delay.” A straightforward reading of this language limits the exemption to emissions exceeding the waste emissions threshold. In addition, since charges would not be imposed on emissions below the threshold, an exemption is unnecessary in cases where facility emissions are below the threshold. The EPA proposes that emissions from facilities that are below the waste emissions threshold would not be exempted. The EPA proposes that for facilities that exceed the waste emissions threshold, emissions eligible for the permitting delay exemption would be subtracted from the facility emissions that exceed the waste emissions threshold. The exempted emissions would not be used to reduce emissions totals below the threshold (*i.e.,* the lowest possible WEC applicable emissions for a facility with the exemption would be zero).

The second criterion relates to responsiveness on the part of the production sector WEC applicable facility reporting emissions caused by a delay in gathering or transmission infrastructure and the gathering or transmission infrastructure permit applicant: neither the entity potentially eligible for the exemption (*i.e.,* a WEC applicable facility in the onshore or offshore production sector) nor the entity seeking the environmental permit (*e.g.,* an entity seeking a permit for gathering or transmission infrastructure) has contributed to the delay in permitting.

The EPA is proposing that contributions to the delay by either the production entity potentially eligible for the exemption or the entity seeking the environmental permit would be determined based upon the timeliness of response to requests for additional information or modification of the permit application. Delays in response exceeding the response time requested by the permitting agency, or requested by the relevant production or gathering or transmission infrastructure entity seeking the permit, or responses that exceed 30 days from the request if no specific response time is requested, would be considered to contribute to the delay in processing the permit application. Note that this proposed determination of what would constitute a delay eligible for the exemption in environmental permitting would be specific solely to implementation of CAA section 136(f)(5) and this proposed rulemaking for part 99, and would not necessarily be applicable to any other section of the CAA, or any permitting program administered by the EPA or by a state or local permitting authority.

The third criterion is that the exempted emissions must be those resulting from the flaring of gas that would have been mitigated without the permit delay – and that exempted emissions must be in compliance with all applicable local, state, and Federal regulations regarding flaring emissions. The EPA believes that this approach reasonably follows from the text of section 136(f)(5), which exempts emissions caused by unreasonable delay in the permitting of "gathering or transmission infrastructure *necessary for offtake of increased volume as a result of methane emissions mitigation implementation*."[27] Following this statutory directive, the EPA is proposing that exempted emissions are flaring emissions which (1) would otherwise be captured in accordance with applicable regulations but (2) are not captured due to a delay in the permitting necessary for offtake. It is anticipated that operations seeking the exemption could include oil production sites planning to send gas to sale, rather than flaring the emissions, or facilities that produce natural gas, condensate or natural gas liquids and that expand operations and are flaring gas because a pipeline is not yet available. Only flaring emissions caused by the unreasonable delay in permitting, and occurring in compliance with all applicable regulations, would be exempt. Other emissions occurring at the wellsite would not be exempt because they are not associated with the delay or because they do not occur in compliance with applicable regulations. For example, fugitive emissions from leaks would occur with or without the delayed

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[27] 42 U.S.C. 7436(f)(5) (emphasis added).

infrastructure, and venting emissions is widely restricted due to Federal, state, or local regulations on venting.

Flaring emissions that occur as a result of flaring that is not in compliance with applicable regulations are ineligible for the exemption. This approach accords with the text of section 136(f)(5), which states that the exemption is for emissions occurring as a result of unreasonable delay in permitting required for the build out of infrastructure "necessary for offtake of increased volume *as a result of* methane emissions mitigation."[28] Regulations limiting flaring and venting will result in an increased volume of gas that must be captured and transmitted, compared with a circumstance without methane emissions mitigation implementation, in which gas is flared or vented on site. Thus, the EPA understands that this provision is designed to exempt flaring done in compliance with regulations, where sources are prepared to capture gas but cannot yet do so due to lack of offtake infrastructure. However, a delay in permitting does not allow exemption from other applicable local, state, and Federal regulations regarding flaring. Thus, the flaring emissions exempt under 136(f)(5) cannot exceed flaring emissions allowable under other applicable local, state, and Federal regulations.

The fourth criterion is that an eligible "unreasonable delay" would be a delay that exceeds a set period of months specified in the final rule. The EPA's current assessment is that this time period would likely fall somewhere between 30 and 42 months from the date that a submitted permit application was determined to be complete by the relevant permitting authority. This time period is not tied to the timing of the WEC; a facility that meets all four criteria would be eligible for the exemption in the first year of the WEC if the time period requirement has been met. The relevant permitting authority could be the United States Federal Energy Regulatory Commission (FERC), or other federal, state or local agencies that issue environmental permits. The environmental permitting process can require multiple steps including, but not limited to: the entity preparing and submitting a permit application; the entity responding to comments with

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[28] 42 U.S.C. 7436(f)(5)

supporting information; the regulatory agency preparing a draft permit; public comment; and preparation and issuance of the final permit. Target dates for permit actions can vary by regulatory agency and depend, for example, on whether the relevant permit is for a new or existing source, or whether the action is a major or minor modification. The EPA is proposing to set a timeframe for unreasonable delay that is not specific to particular permitting actions or agency timelines.

The EPA is proposing to set a timeline somewhere in the range of 30 to 42 months, with the default to be specified in the final rule after consideration of comments received. This preliminary range is based on the EPA's current understanding of timelines for oil and gas permitting across Federal agencies. In particular, the preliminary range is informed by the EPA's review of data made available through the Federal Permitting Improvement Steering Council (FPISC) through Title 41 of the Fixing America's Surface Transportation Act (FAST-41). The "Recommended Performance Schedules for 2020" released by FPISC contains data for the Federal review and permitting of 18 pipeline projects under the FAST-41 program.[29] For these projects, the mean time from receipt by FERC of a complete application to the issuance of a certificate of public convenience and necessity for interstate natural gas pipelines was 23 months, with three of the 18 projects (17 percent) exceeding 30 months. Criteria for inclusion in the FAST-41 program include projects that are considered likely to require investment exceeding $200,000,000 and that do not qualify for abbreviated review under applicable law; or projects of a size and complexity that the FPISC determines are likely to benefit from inclusion.[30] On this basis, the EPA believes the FAST-41 dataset may be a conservative population (*i.e.*, require

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[29] Federal Permitting Improvement Steering Council, "2020 Recommended Performance Schedules." Federal Infrastructure Permitting Dashboard. April 6, 2020. *https://www.permits.performance.gov/fpisc-content/recommended-performance-schedules*. Accessed August 28, 2023.

[30] Federal Permitting Improvement Steering Council, "FAST-41 Fact Sheet." Federal Infrastructure Permitting Dashboard. September 13, 2022. *https://www.permits.performance.gov/documentation/fast-41-fact-sheet*. Accessed August 28, 2023.

more complex environmental review and permitting) when compared to the total of all gathering or transmission infrastructure projects.

The proposed range of 30 to 42 months also takes into account the 2023 Fiscal Responsibility Act, which set a limit under the National Environmental Policy Act of 1 year for completion of an Environmental Assessment and 2 years for completion of an Environmental Impact Statement unless extended by the lead agency in consultation with the applicant or project sponsor. However, the amount of time necessary to complete an Environmental Assessment or Environmental Impact Statement will vary depending on the specific agency action at issue, and this proposed timeline is not intended to reflect a determination of the reasonable length of a time necessary to complete such analysis in any specific instance. For projects requiring approval or permitting from a federal agency, completion of an Environmental Assessment or Environmental Impact Statement must occur prior to the agency taking a final agency action. Additional steps in the process that must be completed following completion of review under NEPA may add several months to the overall timeframe (*e.g.,* convening of FERC to approve or deny a certificate of public convenience and necessity).

We note that all four criteria must have been met for the EPA to determine that for the purpose of this exemption, emissions were caused by an unreasonable delay. No single factor, including timing, would be determinative as to whether a delay unreasonable in the context of this exemption. We are not assessing whether a delay of any particular period of months alone (i.e., in the absence of the other three criteria) should be considered unreasonable in the context of this exemption, and we are not assessing the reasonableness of a particular timeframe or collection of conditions outside of the context of this exemption specific to CAA section 136. An assessment of reasonableness in any other context depends on the circumstances specific to that context, which can vary considerably and there is no straightforward way to determine whether a delay is reasonable or unreasonable that applies to all contexts. We note that using the approach of requiring four criteria to be met may not fully capture case-by-case circumstances and therefore may not always produce the same determination as a more holistic evaluation would. We have proposed this approach of using four criteria, including one specifying a set timeframe, for the purposes of this exemption only to simplify this process, and for clarity and administrability; we understand that longer permitting timeframes are often not unreasonable in other contexts.

As an alternative to specifying that an “unreasonable delay” requires a set period of months to have elapsed since a permit application is deemed complete (in addition to the other three criteria), the EPA considered adopting a case-by-case process for determining whether an unreasonable delay in permitting has occurred. Under such an approach, the exemption for unreasonable delay could only be utilized by a facility that has obtained a facility-specific finding of unreasonable delay from the EPA. The EPA would evaluate documentation provided by a WEC obligated party to determine if there was an unreasonable delay. A WEC obligated party would not exclude emissions it claimed are associated with the unreasonable delay exemption until such time as it obtained an unreasonable delay finding from the EPA. In other words, emissions associated with a claim of unreasonable delay for which there is not an unreasonable delay determination by the EPA could not be subtracted from the emissions totals in the initial WEC filing. If the EPA subsequently were to make such a finding, the EPA would authorize a refund in accordance with its determination. Documentation could include information such as that currently proposed to be reported, such as information on mitigation activities, permitting timing, and regulations relevant to flaring, and information currently proposed as recordkeeping requirements, such as detailed records on responsiveness, in addition to other documentation specific to the relevant gathering or transmission infrastructure environmental permit, such as on the expected timing for the specific environmental permit(s) sought and the type of information that would be needed to support the claim that the permit(s) is delayed beyond what could be considered a reasonable timeframe. A case-by-case approach for reviewing and approving the unreasonable delay exemption would help ensure the validity of individual claims, and ensure that all applicable waste emissions for each facility are subject to charge, as directed by Congress. However, the EPA decided not to propose such an approach due to the time and resource burden that would be required to administer such a process, for both covered entities and for the EPA. We expect that many types of permitting situations can arise, with many permutations. If industry were required to demonstrate unreasonable delay on a case-by-case basis, the EPA anticipates this review process would result in uncertainty for industry and could lead to a significant backlog, thus making the annual calculation of the WEC unduly burdensome. Therefore, in the interest of simplicity and making the exemption available in an efficient manner and without significant additional burden, the EPA proposes to rely on this threshold of a set period of months, in addition to the three other criteria, which can be more easily applied without detailed investigation. The EPA notes that in its verification process under the proposed approach it would review the submitted documentation to confirm that requirements are met for each facility reporting an unreasonable delay, and facilities determined to have not met the requirements would be required to submit any additional owed WEC obligation and relevant penalties.

Section II.D.1.c. below details the reporting requirements for this exemption which provide information necessary for verification of the exemption eligibility and exempted emission quantities.

We seek comment on these four criteria, each required to be met to determine emissions eligible for the unreasonable delay exemption. We seek comment on the use of responsiveness to requests regarding permitting by the permit applicant or the production segment facility experiencing delayed mitigation as a criterion. We seek comment on the use of 30 days to assess responsiveness where a specific timeframe for response is not provided. We seek comment on the criterion that exempted emissions are those resulting from flaring of gas that would have been mitigated without the permit delay, and that only flaring emissions that are in compliance with applicable regulations are eligible. We seek comment on the appropriate timeframe to be used as part of the four-factor test proposed today – specifically, what would be the best period of time (even if it is below or above the 30-42-month range EPA is leaning towards now) to use as a trigger for assessing unreasonable delay for the purposes of CAA section 136(f). We seek comment on the proposed use of one timeframe for eligibility versus an approach that might use different time frames for different types of permits. We seek comment on whether specific types of delays should be eligible or ineligible, which could be included as additional criteria or used in place of all or some of the proposed criteria. For example, we seek comment on whether we should establish that delays due to litigation regarding pipeline development are ineligible. We also seek comment on an alternative case-specific approach in which each facility with exempt emissions from unreasonable delay would provide additional facility- and permit-specific information, and in which the exemption would not be granted unless approved by the EPA. Finally, we seek comment on whether EPA should include additional criteria when defining the unreasonable delay exemption. For example, we seek comment on whether, in addition to the four criteria, we should add a criterion that entities show the flaring is necessary (i.e., other options for beneficially use or reinject of gas were infeasible).

b. Calculation of Emissions Resulting From an Unreasonable Delay

Through the provisions proposed at 40 CFR 99.32, the EPA is proposing that exempted emissions are flaring emissions caused by the delay. We are proposing that exempted flaring emissions are the methane emissions (or a subset of the methane emissions) from flaring reported under subpart W.

To calculate the exempted emissions quantity, the entity must determine the time period associated with the emissions that occurred as a result of the delay within the filing year. The EPA is proposing that the delay begins when emissions would have been avoided through the operation of the gathering or transmission infrastructure, not when construction would begin, as in many cases the infrastructure would not be immediately in place and operational at the time of permitting approval. For example, a permit to construct might be needed before construction begins, and construction could take months or more before the infrastructure would be in place.

Where the exempted emissions cover the entire reporting year, the exempted flaring emissions would be the total reported to part 98 for flare stacks, associated gas flaring, and the portion of offshore methane emissions attributable to flaring. Where exempted emissions occur in only a fraction of a reporting year, the facility is to use data on flaring emissions over that time frame if available, and if unavailable, the facility is to adjust part 98 flaring emissions using the fraction of the year that the exemption is available. Where flared emissions impacted by permitting delay only account for a portion of the total flared emissions, the facility is to adjust their part 98 reported flaring emissions using company records and/or engineering calculations.

We seek comment on the provisions proposed, including the use of reported flaring emissions to determine exempted emissions, the use of part 98 data, and the approaches for quantifying emissions for fractions of the reporting year.

c. Reporting and Recordkeeping Requirements for the Exemption for Emissions Resulting from a Permit Delay

Through the provisions proposed at 40 CFR 99.31, the EPA is proposing that the WEC obligated party receiving the exemption would provide information on each well pad or offshore platform impacted by the delay. This includes the type of permit, permitting authority, and the date that the permit application was complete. The WEC obligated party must report the planned timing of the commencement of the offtake of gas had the permit not been delayed. This includes a listing of the methane emissions mitigation activities that are impacted by the delay and the flaring emissions associated with natural gas that would have been directed to gathering or transmission infrastructure as a result of the methane emissions mitigation activities. This also includes information on all applicable local, state, and Federal regulations regarding flaring emissions and the facility’s compliance with each. The WEC obligated party must report the time period associated with the emissions that occurred as a result of the delay within the filing year. The WEC obligated party must also affirm that neither the production segment entity impacted by the delay nor the gathering or transmission infrastructure entity seeking the permit contributed to the unreasonable delay.

The EPA requires this information for the verification of exemption eligibility and of exempted emission quantity. Reported information will be used to conduct verification as discussed in section III.A.4., and reported information, records and other information as applicable will be used to conduct any auditing that occurs under section III.E.1.

The EPA seeks comment on the reporting and recordkeeping requirements for the exemption for unreasonable delay in environmental permitting. We seek comment on whether additional information should be collected or retained to allow for verification of the quantity of emissions eligible for the exemption.

2. Regulatory Compliance Exemption Under CAA Section 136(f)(6)

CAA section 136(f)(6) establishes a regulatory compliance exemption for subpart W facilities that are “subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111” upon an Administrator determination that the criteria at CAA section 136(f)(6)(A) have been met. In this action, the EPA is proposing: when the Administrator determinations will be made; the time at which the regulatory compliance exemption would become available to eligible facilities; the process for how the Administrator determinations will be made; how to interpret CAA section 136(f)(6)(A) to govern the interaction between WEC applicable facilities and CAA section 111(b) affected facilities and CAA section 111(d) designated facilities (collectively referred to in this preamble as “CAA section 111(b) and (d) facilities”) for the purposes of the regulatory compliance exemption; how “compliance” with the methane emissions requirements promulgated under CAA sections 111(b) and (d) will be defined for the purposes of the regulatory compliance exemption; reporting requirements for the regulatory compliance exemption; and the process for resumption of the

WEC pursuant to CAA section 136(f)(6)(B) if the criteria for the regulatory compliance exemption are no longer met.

The EPA believes the Congressional intent of this exemption was twofold: 1) to be implemented such that the WEC acts as a bridge to full implementation of the Final NSPS OOOOb and EG OOOOc by encouraging methane reductions in the near term while state plans are being developed, and thereafter exempting from the charge facilities that are in compliance with the requirements pursuant to the final NSPS OOOOb and EG-OOOOc-implementing state and Federal plans,[31] and 2) to encourage timely implementation of requirements in the final NSPS OOOOb and EG OOOOc-implementing state and Federal plans in order to ensure that those requirements achieve meaningful emissions reductions. The EPA's proposed approach for implementing the regulatory compliance exemption is based on a plain reading of the statutory text in CAA section 136(f)(6). The EPA strives to create a program that is straightforward to implement and enforce.

The EPA interprets the intent of the WEC to be to incentivize reduction of methane emissions across the oil and gas industry. For industry segments not covered by NSPS OOOOb/EG OOOOc, the WEC incentivizes, but does not require, early and sustained emissions mitigation activity. For WEC applicable facilities in industry segments that are covered by NSPS OOOOb/EG OOOOc, the WEC incentivizes, but does not require, methane emissions reductions

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[31] Under the Tribal Authority Rule (TAR), eligible Tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a Tribal implementation plan (TIP) implementing the EG codified in 40 CFR part 60, subpart OOOOc. The TAR authorizes Tribes to develop and implement their own air quality programs, or portions thereof, under the CAA. However, it does not require Tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. If a Tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities. In this proposal, all uses of the phrase "state and Federal plans" are intended to include any Tribal plans, to the extent that any Tribal plans are developed to implement EG OOOOc.

earlier than may otherwise be required pursuant to NSPS OOOOb and EG OOOOc-derived state and Federal plans. Once those requirements are in effect, the EPA believes the purpose of the regulatory compliance exemption is to provide relief from the WEC to owners or operators that are fully complying with those requirements, and to broadly encourage compliance. This structure ensures that there is an incentive (or requirement) for methane emission reductions from new and existing sources in place at all times, while also avoiding regulation of the same emissions under both the WEC and the NSPS OOOOb and EG OOOOc-implementing state and Federal plans once the regulatory compliance exemption becomes available.

The EPA expects that, as CAA section 111(b) and (d) facilities implement and comply with the methane emissions requirements of NSPS OOOOb and EG OOOOc-implementing state and Federal plans, many of the WEC applicable facilities that contain those emissions sources subject to NSPS OOOOb and EG OOOOc-derived state and Federal plans would be expected to fall below the waste emissions thresholds, and thus not be subject to the WEC. However, the regulatory compliance exemption recognizes that certain WEC applicable facilities may remain above the waste emissions thresholds even after implementation of the requirements in the final NSPS OOOOb and approved state and Federal plans under EG OOOOc; the regulatory compliance exemption would shield such owners or operators that are in compliance with those requirements from additional regulation under the WEC.

Congress provided that the regulatory compliance exemption would only come into effect after "(i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities" and "(ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by [the NSPS OOOOb/EG OOOOc 2021 Proposal], if such rule had been finalized and implemented." The EPA's understanding of these provisions is that Congress intended to provide an incentive for states to move promptly in adopting their plans, and to encourage those plans to achieve meaningful emissions reductions.

These two drivers are manifested in the Administrator determinations that must be made before the regulatory compliance exemption becomes available: the first Administrator determination, per CAA section 136(f)(6)(A)(i), that the final NSPS OOOOb and all EG OOOOc-implementing state and Federal plans are "approved and in effect"; and the second Administrator determination, per section 136(f)(6)(A)(ii), that the emissions reductions achieved by these requirements are equal to or greater than the reductions that would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal, had that rule been finalized and implemented as proposed (the "equivalency determination"). These requirements mean that if the final NSPS OOOOb or EG OOOOc-implementing state or Federal plans are delayed, or the requirements therein are collectively less stringent than those in the NSPS OOOOb/EG OOOOc 2021 Proposal, the exemption would not be available and WEC applicable facilities that exceed the waste emissions threshold would not be eligible for the regulatory compliance exemption from the WEC until the conditions are met.

Here, we summarize the proposed approach for the regulatory compliance exemption. Elements of the proposal, other options considered, and requests for comment are discussed in more detail in the sections below.

The EPA is proposing that the prerequisite Administrator determinations for the regulatory compliance exemption would be made after all state and Federal plans pursuant to CAA section 111(d) are approved and in effect. Separate from the timing of the Administrator determinations, the WEC program must establish when the regulatory compliance exemption becomes available at the facility level (*i.e.*, when eligible facilities can be exempted from the WEC), by defining when WEC applicable facilities that are subject to methane emissions requirements pursuant to NSPS OOOOb and EG OOOOc-implementing state and federal plans are in compliance with those requirements. The EPA believes that the regulatory compliance exemption is intended to provide relief from the WEC when the requirements in the final NSPS OOOOb and EG OOOOc-implementing state and Federal plans are in effect in all states. In this interest, the EPA is proposing that WEC applicable facilities would be eligible for the regulatory compliance exemption as soon as the Administrator determinations have been made, rather than when the applicable requirements in state and Federal plans are fully implemented. Thus, under the EPA's proposed approach, the regulatory compliance exemption would become available to facilities as soon as the Administrator determinations are made under CAA section 136(f)(6)(A)(i) and (ii).

The EPA is also proposing further elements of the process for the Administrator determinations under CAA section 136(f)(6)(A)(i) and (ii), including establishing the relative points of comparison for the equivalency determination, in order to ensure that those elements align with the statutory requirements. Because the Administrator determinations cannot be made until all plans are approved and in effect, and because the timing for both Administrator determinations is aligned, the EPA proposes that two the determinations be made together via a single future administrative action.

The EPA is proposing that a WEC applicable facility's eligibility for the regulatory compliance exemption would be based on the compliance status of all of the CAA section 111(b) and (d) facilities contained within that WEC applicable facility. To be eligible for the exemption, the EPA proposes that all of the regulated emissions sources must be in full compliance with their respective methane emissions requirements under the NSPS and EG-implementing state and Federal plans.

The EPA is also proposing reporting requirements for the regulatory compliance exemption. In order to reduce the burden on industry, the EPA proposes that only WEC applicable facilities that are eligible for the exemption would be required to report all associated data elements. Finally, the EPA is proposing how access to the regulatory compliance exemption would be removed for all WEC applicable facilities if the criteria associated with the Administrator determinations were no longer met. The EPA's proposed approach for removing access to the exemption mirrors the conditions that must be met in order for it to become available.

a. Timing for Regulatory Compliance Determinations

Before the regulatory compliance exemption becomes available to facilities, CAA section 136(f)(6)(A) requires determinations to be made by the Administrator that (1) "methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities" and (2) that "compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the [NSPS OOOOb/EG OOOOc 2021 Proposal], if such rule had been finalized and implemented." The EPA believes that Congress intended these prerequisites to exemption availability to encourage timely implementation of the requirements in the final NSPS and state and Federal plans and to ensure that those requirements achieve meaningful emissions reductions.

The first Administrator determination is related to the timing of final methane emissions standards under CAA section 111(b) and state and Federal plans pursuant to an EG issued under CAA section 111(d). The EPA proposes to interpret the language in CAA section 136(f)(6)(A)(i) to mean that this temporal requirement is only met when <u>*both*</u> (1) emission standards for new sources under CAA section 111(b) are promulgated and in effect and (2) all state plans for existing sources pursuant to an EG issued under CAA section 111(d) have been approved by the EPA and are in effect. As to the latter element, the EPA also proposes to interpret the reference to "plans pursuant to subsection... (d) of section 111" to include the promulgation of a Federal plan where the EPA determines that one or more states have failed to submit an approvable state plan, as that is the only way a plan pursuant to CAA section 111(d) would take effect in those states. The EPA further proposes to interpret "all states" in CAA section 136(f)(6)(A)(i) to mean that every state with an applicable facility (*i.e.*, all states with subpart W facilities containing CAA section 111(b) or (d) facilities) must have an approved plan (state or Federal) before the determination can be made. Accordingly, because the emissions standards for new sources under CAA section 111(b) will be finalized before the submittal of state plans for existing sources under CAA section 111(d), approval of the final state (or Federal) plan for states with designated facilities would determine the timing for when the determination could be made under the proposed approach. The EPA proposes that this determination would be made after all CAA section 111(d) plans (*i.e.*, state or Federal plans) have been approved and are in effect. The EPA believes that the proposed approach and interpretation of "all states" is aligned with a plain reading of the statutory text. In particular, the EPA notes the relationship between the use of the singular in section 136(f)(6)(A), directing the EPA to make "a determination", and the requirements outlined in 136(f)(6)(A)(ii) and (ii), providing that this determination is dependent on EPA finding that (1) standards and plans "have been approved and are in effect in all states" and that (2) compliance with the standards and plans "will result in equivalent or greater emissions reductions as would be achieved by the [2021] proposed rule…"[32] The text strongly indicates that the EPA must make *one* determination after all standards and plans are in place in all states in order to make the exemption available, and further that the determination cannot be made until standards and plans are in place in all states because the equivalency determination must be made on a nationwide scale.[33]

The EPA considered an alternative approach for the determination that methane emissions standards and plans have been approved and are in effect in all states. This alternative would involve a determination for methane emissions standards after the promulgation of final emissions standards for CAA section 111(b) facilities and then determinations on a state-by-state basis as each state plan containing emissions standards for CAA section 111(d) facilities were

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[32] 42 U.S.C. 7436(f)(6)(A).

[33] Note that while the EPA believes that the statute instructs us to make a determination after the plans are collectively in place (rather than making multiple state-by-state determinations), that does not preclude the EPA from reviewing and revising the determination if a standard or plan is later revised, to ensure that the conditions of section 136(f)(6)(A) are still met, consistent with the resumption of charge language in section 136(f)(6)(B).

submitted and approved by the EPA (or a Federal plan was promulgated where a state did not submit an approvable plan). The EPA believes that this state-by-state approach is inconsistent with a plain reading of CAA section 136(f)(6)(A)(i), which mandates that emissions standards and plans must be approved and in effect in *all* states with respect to the applicable facilities (*i.e.*, all states with subpart W facilities containing CAA section 111(b) or (d) facilities). The EPA requests comment on the proposed approach and an alternative approach that would make determinations on a state-by-state basis as each state plan was approved.

The second determination that must be made before the regulatory compliance exemption becomes available is whether the final “methane emissions standards and plans” provide equivalent or greater emissions reductions than would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal, had that proposal been finalized and implemented as proposed. Based on a plain reading of the statutory text, because plans pursuant to CAA section 111(d) will not be finalized for several years, the EPA cannot propose an equivalency determination in this action. Instead, we propose that the equivalency determination will be made via an administrative action after all CAA section 111(d) plans (*i.e.*, state or Federal plans) have been approved. This proposed timing would allow evaluation of the emissions reductions achieved by the final NSPS and by all final state and Federal plans.

The EPA also assessed making the equivalency determination for CAA section 111(b) affected facilities before making it for CAA section 111(d) designated facilities. In this proposal, the EPA interprets CAA section 136(f)(6)(ii) as requiring a comparison of the emissions reductions that will be achieved by the final NSPS OOOOb/EG OOOOc and the reductions that would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal if finalized as proposed. Separate equivalency determinations for CAA section 111(b) facilities and CAA section 111(d) facilities would not provide for a comparison of the total emissions reductions achieved by both rules, and therefore the EPA believes that an approach with separate equivalency determinations would be inconsistent with a plain reading of the statutory text.

Further, because both determinations must occur before the exemption becomes available, and because under the proposed approach the determination required by CAA section 136(f)(6)(i) would occur after all plans are approved and in effect, there would be no practical reason for making the equivalency determination for CAA section 111(b) facilities before making it for CAA section 111(d) facilities. Finally, the only purpose for making the equivalency determination for CAA section 111(b) facilities before CAA section 111(d) facilities would be in support of an approach that would make the regulatory compliance exemption available to CAA section 111(b) facilities before CAA section 111(d) facilities. As discussed below in section II.D.2.b of this preamble, such an approach would not align with other elements of this proposal, would not be aligned with the statutory text, and would not be technically feasible. The EPA requests comment on this alternative approach.

b. Timing of Regulatory Compliance Exemption Availability

Separate from the timing of the Administrator determinations, the WEC program must also establish when the regulatory compliance exemption will become available for facilities. Different states will have different start dates and in some cases, phased-in requirements, in state or federal plans under 111(d), resulting in some facilities being in compliance with the methane emissions requirements pursuant to CAA section 111(b) and (d) before others. The EPA believes the inclusion of the regulatory compliance exemption at CAA section 136(f)(6)allows for relief from the WEC when the requirements in the final NSPS and state and Federal plans are in effect. The EPA therefore proposes that the regulatory compliance exemption would become available to all applicable facilities meeting the criteria when the Administrator determinations required by CAA section 136(f)(6)(A)(i) and (ii) have both been made. Both determinations are required before the exemption becomes available, and the determination under CAA section 136(f)(6)(A)(i) would indicate that the requirements promulgated under CAA sections 111(b) and (d) have been approved and are in effect. Because the availability of the exemption is linked to the CAA section 136(f)(6)(A)(i) and (ii) determinations, which the EPA is proposing could only be made after all states with an applicable facility have an approved state or Federal plan in effect, the EPA is proposing that the exemption would become available to all eligible WEC applicable facilities in all states at the same time. Moreover, because methane emissions standards for CAA section 111(b) facilities would be expected to come into effect earlier than those required for CAA section 111(d) facilities in state or Federal plans, the timing for exemption availability would be largely driven by the approval and effective date for the final state or Federal plan (i.e., the last state with CAA section 111(d) facilities to have a plan approved and in effect).

The EPA believes the proposed approach is consistent with the statutory text. CAA section 136(f)(6)(A) states that charges shall not be imposed on an applicable facility "that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111." In order to receive the exemption, all CAA section 111(b) and (d) facilities contained within a WEC applicable facility would need to demonstrate compliance, as discussed in section II.D.2.f. of this preamble.

This proposal makes the exemption available upon adoption of all plans pursuant to CAA section 111(d) and the issuance of the Administrator's findings under CAA section 136(f)(6)(A). The EPA proposes that the exemption be available as soon as all state or federal plans are in effect, because facilities can be in compliance with the requirements in plan even if full implementation of those requirements is not required until a future date. Provided that facilities subject to the WEC are in compliance with OOOOb requirements and the requirements in EG OOOOc-implementing plans, the proposed approach also allows such facilities to benefit from the regulatory compliance exemption much earlier than the alternative, described below, of making the regulatory compliance exemption available only once applicable compliance deadlines have passed.

The EPA notes that implementation of the requirements included in state or Federal plans may not be mandated immediately upon the date at which the plan goes into effect. In other words, the plans may include compliance schedules with compliance dates that occur at a future date after plan approval, and such requirements could be implemented over multiple compliance dates in a phased manner or include deadlines for various increments of progress. It is therefore possible for CAA section 111(d) facilities to be in compliance with the methane emissions requirements in a plan even if not all compliance dates included in the plan have come to pass. For example, if an approved state plan were to require a specific type of designated facilities to install emissions controls within a year of the effective date of the state plan, those facilities would be considered in compliance with those requirements for that first year. By providing the exemption as soon as the Administrator's determinations are made after state or Federal plans are approved and in effect rather than when the requirements in those plans must be implemented, the proposed approach would provide relief from the WEC once CAA section 111(d) facilities are effectively subject to federally enforceable methane emissions requirements pursuant to CAA section 111. The EPA requests comment on the proposed approach of making the regulatory compliance exemption available to all WEC applicable facilities at the time when the two determinations required by CAA section 136(f)(6)(A) have been made.

The EPA considered alternative approaches in developing this proposal for implementing the regulatory compliance exemption but found they would not be consistent with the statutory text, would be more challenging to implement, would unfairly advantage specific facilities and companies, or would not be technically feasible.

First, the EPA considered an approach that would make the exemption available to WEC applicable facilities meeting the criteria at a state-by-state level as the plan pursuant to CAA section 111(d) for each state was approved and became effective. For WEC applicable facilities that span multiple states, the exemption would be available when plans for all states in which the facility is located were approved and in effect. This alternative approach would likely make the exemption available earlier for certain WEC applicable facilities compared to the proposed approach, which would not make the exemption available until plans are approved and in effect in all states. The EPA believes that making the regulatory compliance available at a state-by-state level is inconsistent with the statutory text. As discussed in section II.D.2.a. of this preamble, the EPA's interpretation of CAA section 136(f)(6)(A) in this proposal is that neither of the determinations that are prerequisites to the regulatory compliance exemption's availability could be made until plans for CAA section 111(d) facilities have been approved and are in effect for all states. Based on this interpretation, it would not be possible for the exemption to become available on a state-by-state basis as state plans were approved and became effective because the prerequisite determinations could not occur until all state plans were approved and in effect. The EPA also believes the proposed approach will simplify implementation and administration of the regulatory compliance exemption compared to an approach in which the exemption would become available to states at different times. Further, a state-by-state application of the exemption could unfairly advantage and disadvantage WEC applicability facilities or companies based on their geographic location. WEC obligations for operations in states that take longer to develop state plans could be higher than those in states that are able to develop and have plans approved earlier, and thus have access to the exemption. Conversely, the proposed approach of making the exemption available to all states at the same time would be equitable and provide the industry with better regulatory certainty. The EPA requests comment on making the regulatory compliance exemption available on a state-by-state basis based on the finalization of plans for individual states.

Second, the EPA considered an approach that would make the regulatory compliance exemption available to WEC applicable facilities meeting the criteria when the methane requirements for all CAA section 111(b) and (d) facilities have been fully implemented. Under this alternative approach, WEC applicable facilities would only become eligible for the regularly compliance exemption once the compliance dates for the NSPS and the state and Federal plans have passed. Because the compliance deadlines under the final EG OOOOc may occur at some point *after* the timeline for state plan approval and issuance of a Federal plan, this alternative approach would make the regulatory compliance exemption available later than under the proposed approach. This would require the EPA to interpret the phrase "subject to and in compliance with methane emissions requirements" in CAA section 136(f)(A) to mean that the exemption from the charge is available only after all of the requirements for CAA section 111(d) facilities have been fully implemented. In other words, the EPA would read "in compliance with methane emissions requirements" to mean that *all* compliance dates in the NSPS and the state and Federal plans have passed. That might serve to give independent effect to both elements of the statutory phrase "subject to and in compliance with", but the EPA believes that this alternative approach is not as well aligned with the statutory directive. This is because compliance with the standards may occur at different points in time, both across the NSPS and the state and Federal plans, and even within standards that have phased compliance requirements. This interpretation may have the result of delaying availability of the regulatory compliance exemption for many years, even as facilities are otherwise complying with all *applicable* methane emissions requirements, thus extending the period for which many oil and gas operations would be subject to concurrent regulation under WEC and CAA section 111. Rather, the EPA proposes to conclude that CAA section 111(b) and (d) facilities can be considered to be in compliance with all applicable methane emissions requirements, even prior to the final compliance deadlines, for purposes of the regulatory compliance exemption. While the EPA is not proposing that the exemption would become available when the requirements of all state and Federal plans are fully implemented rather than when all state and Federal plans have been approved and are in effect, the agency requests comment on whether such an approach would be legally and practically justified.

Third, the EPA considered an approach that would make the regulatory compliance exemption available to WEC applicable facilities meeting the criteria at a state-by-state level as the final compliance deadline in a state or Federal plan for CAA section 111(d) facilities was reached. Under this alternative approach, WEC applicable facilities in a given state would have access to the exemption upon the final compliance date for CAA section 111(d) facilities in that state. Because state and Federal plans may establish different compliance timelines for CAA section 111(d) facilities, this approach could make the exemption available to states at different times. For WEC applicable facilities that span multiple states, the exemption would be available when the final compliance date passed in all states in which the facility is located. As with the alternative approach that would make the exemption available after the final compliance deadline for CAA section 111(d) facilities had passed in all states, the EPA does not believe an approach that provides the exemption at a state-by-state level based on compliance dates is as consistent with the statutory text and purpose of the exemption for the reasons discussed in the prior paragraph. The EPA requests comment on an approach that would make the exemption available at a state-by-state level based on each state's final compliance deadline for CAA section 111(d) facilities.

The EPA also assessed an approach that would make the regulatory compliance exemption available to CAA section 111(b) facilities before CAA section 111(d) facilities. Because compliance with emission standards for CAA section 111(b) affected facilities generally apply upon the effective date of the final NSPS and would be required before emission standards for CAA section 111(d) designated facilities are fully implemented (once state or Federal plans are finalized and in effect), there would likely be several years between compliance with methane emissions requirements for CAA section 111(b) and (d) facilities. The EPA rejected this approach for this proposal, however, based on a plain reading of the statutory text. First, as discussed in section II.D.2.e. of this preamble, the exemption is applied to an entire WEC applicable facility, not the CAA section 111(b) and (d) facilities within that WEC applicable facility, and therefore individual CAA section 111(b) or (d) facilities within a WEC applicable facility cannot be exempted. Second, CAA section 136(f)(6)(A) states that waste emission charges shall not be imposed "on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) *and* (d) of section 111." The EPA believes that a plain reading of this text indicates that compliance with regulations pursuant to both CAA section 111(b) and (d) must be achieved before the exemption becomes available, and that the statute therefore does not, by its terms, permit application of the exemption to CAA section 111(b) facilities before it becomes available to CAA section 111(d) facilities. As discussed in section II.D.2.a. of this preamble, the EPA proposes to make the determinations required by CAA section 136(f)(6)(A)(i) and (ii) after all state or Federal plans have been approved and are in effect. Because the determinations that are required for the exemption to become available would not be made separately for CAA section 111(b) facilities and CAA section 111(d) facilities, the exemption would not be available to CAA section 111(b) facilities before CAA section 111(d) facilities under the proposed approach.

Further, even assuming that this statutory text allowed for some ambiguity, there are practical limitations to implementing the regulatory exemption in a phased manner for CAA section 111(b) and (d) facilities. The WEC calculations are based on methane emissions and natural gas or oil throughput data for subpart W facilities that may contain both CAA section 111(b) and (d) facilities. Because reporting under subpart W does not distinguish between CAA section 111(b) and (d) facilities, there is currently no practical means of implementing a phased implementation of the regulatory compliance exemption. Revising the subpart W reporting requirements to make such distinctions would significantly increase the reporting complexity and burden for the oil and gas industry and would not be possible for certain emissions sources due to different definitions of individual emissions source types in subpart W and at CAA section 111(b) and (d) facilities. Further, while it may be feasible to distinguish emissions from new and existing sources for certain emission source categories, there is no means to distinguish natural gas throughput from CAA section 111(b) and (d) facilities at subpart W facilities that contain both CAA section 111(b) and (d) facilities.

c. Emissions Year in Which Exemption Takes Effect

While the data collected under subpart W for the purposes of WEC calculation are reported on a calendar-year basis (*i.e.*, a reporting year is a calendar year), the date at which all of the criteria for the regulatory compliance exemption will be met is not yet known and could fall at any point in the course of a reporting year. The EPA is proposing that the regulatory exemption will take effect in the reporting year in which the required conditions are met. For example, if all exemption requirements are met in June 2027, all eligible facilities meeting the proposed compliance requirements discussed in section II.D.2.f. of this preamble would be exempt from the WEC for the entire 2027 reporting year. The proposed approach is aligned with the EPA's interpretation that the regulatory compliance exemption is intended to prevent WEC applicable facilities from being subject to the WEC when their constituent CAA section 111(b) and (d) facilities are in compliance with their applicable standards. The EPA requests comment on the proposed approach, as well as an approach in which the regulatory compliance exemption became effective for eligible facilities in the next calendar year after which all required conditions are met (*e.g.*, if requirements are met in October 2027, the exemption would come into effect for the 2028 reporting year). The EPA also requests comment on an approach that would apply the regulatory exemption for a portion of the reporting year based on when all exemption requirements were met, and how reported emissions and throughput data could be quantified, such as through prorating.

d. Approach for Regulatory Compliance Determinations

In this action, the EPA is proposing certain elements related to the approach for the CAA section 136(f)(6)(A) Administrator determinations that must occur before the regulatory compliance exemption becomes available. The EPA is proposing that both determinations would be made simultaneously via a future administrative action. For the equivalency determination, the EPA is proposing the geographic scale at which the equivalency determination would be conducted and the specific elements that would be compared. The EPA proposes to address all other elements (e.g., cumulative versus year-by-year) of the equivalency determination in a future administrative action when the analysis is conducted.

The EPA proposes that when the criteria for both determinations are met, the determinations would be made through a single administrative action. As discussed in section II.D.2.a. of this preamble, under the proposed approach neither determination could be made until all state and Federal plans pursuant to CAA section 111(d) have been approved and are in effect. Because the timing for both determinations would be aligned, the EPA believes that making both determinations via a single administrative action will facilitate timely access to the regulatory compliance exemption after the CAA section 136(f)(6)(A)(i) and (ii) requirements have been met. The EPA requests comment on the proposed approach for making both determinations via a single future administrative action, as well as on alternative approaches for making the determinations.

Section 136(f)(6)(A)(ii) of the CAA requires an Administrator determination that compliance with the requirements in the final CAA section 111(b) and (d) rules "will result in equivalent or greater emissions reductions as would be achieved by the [NSPS OOOOb/EG OOOOc 2021 Proposal], if such rule had been finalized and implemented." The EPA is proposing to conduct the analysis for the purposes of this equivalency determination at a national level, comparing the national-level emissions reductions that would have been achieved under the NSPS OOOOb/EG OOOOc 2021 Proposal (if finalized as proposed) against those that will be achieved upon implementation of the final NSPS OOOOb/EG OOOOc.

The EPA believes that a national evaluation is the most appropriate geographic scale for the purposes of the equivalency determination. The primary concern for the emissions reductions achieved by the NSPS OOOOb/EG OOOOc in the context of the WEC regulatory compliance exemption are methane emissions. Because the climate impacts of these emissions are dependent on their aggregate quantity rather than where they occur, a national-level evaluation will provide an appropriate comparison of the overall impact of the reductions that would have been achieved under the NSPS OOOOb/EG OOOOc 2021 Proposal and those that will be achieved upon implementation of the final NSPS OOOOb and state and Federal plans implementing OOOOc. The EPA also considers a national evaluation to be consistent with the statutory text in CAA section 136(f)(6)(A)(ii), which requires the Administrator's determination to be based on "compliance with the requirements described in clause (i)," where clause (i) describes the collective "methane emissions standards and plans" required by CAA sections 111(b) and (d).

The EPA assessed alternative approaches that would conduct the equivalency determination at the state-by-state level (*i.e.*, each state would need to demonstrate equivalent or greater emissions reductions) and at both the national and state-by-state levels. However, the EPA is not proposing an approach that would conduct the equivalency at the state-by-state level because the EPA believes that this approach is less consistent with the statutory text and purpose. Determinations for individual states would not indicate if the emissions reductions that will be achieved by the final NSPS and state and Federal plans are equivalent or greater than the reductions that would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal, had that rule been finalized and implemented. In other words, if the EPA were to make determinations for individual states and make the exemption available on a state-by-state basis, that could result in not achieving emission reductions equivalent to the NSPS OOOOb/EG OOOOc 2021 Proposal, thus undermining Congress' intent in drafting this provision to incentivize a minimum level of methane emission reductions via the CAA section 111(b) and (d) regulations. The EPA requests comment on the proposed approach of conducting the equivalency determination at the national scale. The EPA requests comment on conducting the equivalency determination at other geographic scales, such as a state-by-state level, as well as an approach that would require an equivalency determination at both the national and state-by-state levels.

The EPA also considered an alternative approach that would conduct the equivalency analysis at a source-by-source level (at either a national or state-by-state scale). Under this alternative approach, the EPA would compare the reductions achieved by individual sources under the NSPS OOOOb /EG OOOOc 2021 Proposal, had that rule be finalized and implemented, and the final NSPS OOOOb/EG OOOOc. As described above, the climate impacts of methane emissions are based on their aggregate quantity, and it is that quantity, therefore, that is necessary for conducting the equivalency determination. Within the specific context of the equivalency determination, it does not matter if the emissions reductions achieved by an individual source under the final NSPS OOOOb/EG OOOOc achieves fewer reductions than it would have under the NSPS OOOOb /EG OOOOc 2021 Proposal, as long as the total emissions reductions achieved by implementation of the final NSPS OOOOb and EG OOOOc-derived state or federal plans across all sources are equivalent or greater than those that would have been achieved across all sources by the NSPS OOOOb /EG OOOOc 2021 Proposal. The EPA therefore believes that it is not reasonable to conduct the equivalency analysis on a source-by-source level and such an approach is not required by the statutory text. However, the EPA requests comment on using a source-by-source approach for the equivalency determination and requests comment on how such an analysis could be conducted.

Because the NSPS OOOOb/EG OOOOc 2021 Proposal was not itself a final rule at the time Congress enacted this Waste Emissions Charge program, no new source emissions standards or emission guidelines had been finalized for CAA section 111(b) and (d) facilities based on the NSPS OOOOb/EG OOOOc 2021 Proposal, no requirements had been finalized for what constitutes an approvable state plan, and no states had submitted state plans pursuant to such hypothetical finalized requirements. As such, the EPA proposes to use the standards proposed in NSPS OOOOb and the presumptive standards proposed in EG OOOOc as the basis for evaluating emissions reductions that would have been achieved had the NSPS OOOOb/EG OOOOc 2021 Proposal been finalized and implemented. In other words, the EPA understands the inclusion of the NSPS OOOOb/EG OOOOc 2021 Proposal as the baseline for the equivalency demonstration to mean that Congress intended for the EPA to assume, for purposes of this analysis, that the proposed standards were finalized as drafted in the NSPS OOOOb/EG OOOOc 2021 Proposal and implemented nationwide. Further, because Congress directs the EPA to compare the emissions that would have been achieved if the NSPS OOOOb/EG OOOOc 2021 Proposal were finalized and implemented against actual CAA section 111(b) and (d) standards once these are finalized and in effect, the EPA believes that Congress must have meant the EPA to assume that the NSPS OOOOb/EG OOOOc 2021 Proposal was finalized and implemented *as proposed*, which is the only way to use it as a point of comparison. Accordingly, for CAA section 111(b) facilities under the NSPS OOOOb/EG OOOOc 2021 Proposal, the EPA proposes to assess the reductions that would have been achieved had the proposed NSPS OOOOb been finalized and implemented. For CAA section 111(d) facilities under the NSPS OOOOb/EG OOOOc 2021 Proposal, the EPA proposes to assess the reductions that would have been achieved had the proposed emissions guidelines been adopted and implemented by all states as proposed.

The EPA believes the proposed points of comparison between the NSPS OOOOb/EG OOOOc 2021 Proposal and the final NSPS OOOOb and final requirements in state and Federal plans derived from EG OOOOc for the equivalency is aligned with a plain reading of CAA section 136(f)(6)(A), and with Congressional intent. The EPA requests comment on the proposed approach. The EPA recognizes that if the NSPS OOOOb/EG OOOOc 2021 Proposal had been finalized as proposed, the requirements for CAA section 111(d) facilities, and the emissions reductions associated with those requirements, would have been based on approved state or Federal plans. In those plans, it is possible that some states may have set different standards of performance than the presumptive standards proposed in EG OOOOc based on a provision of CAA section 111(d)(1) permitting states to “take into consideration, among other factors, the remaining useful life of a source.” (The EPA refers to this provision as the “remaining useful life and other factors” provision, or RULOF.) The EPA regulations at 40 CFR part 60 subpart Ba permit states to consider several factors to, with an adequate demonstration, establish standards less stringent than the degree of emission limitation otherwise required by an EG. In such circumstances, the emissions reductions achieved by those state plans would have been less than if the state plans had adopted and implemented the presumptive standards in the final emissions guidelines, had they been finalized. However, because state plans were never developed pursuant to the NSPS OOOOb/EG OOOOc 2021 Proposal, there is no means of reasonably estimating the requirements that may have been included in those state plans and what emissions reductions they would have achieved. The text also counsels against making RULOF assumptions in this case. Because Congress directs the EPA to compare the emissions that would have been achieved if the NSPS OOOOb/EG OOOOc 2021 Proposal were "finalized and implemented" against actual CAA section 111(b) and (d) standards once these are "approved and in effect," the EPA believes that Congress meant the Agency to assume that the NSPS OOOOb/EG OOOOc 2021 Proposal was finalized and implemented *as proposed*, because that will allow for comparison with emissions reductions achieved under the final CAA section 111(d) plans, which may differ from the proposal in a variety of ways, including as a result of RULOF analysis. It is also reasonable to infer that Congress wanted to guarantee the level of reductions (i.e., "equivalent or greater"[34] than expected by the NSPS OOOOb/EG OOOOc 2021 Proposal) that would ultimately be achieved by the final NSPS OOOOb and EG OOOOc-derived state and Federal plans by only allowing for the exemption if it is determined that the Final NSPS OOOOb/EG OOOOc would achieve at least the level of reductions that were expected from the proposed rule in place at the time CAA section 136 was written and passed. Thus, the EPA believes the intent of CAA section 136(f)(6)(A) is to use the proposed approach of assessing the reductions that would have been achieved had the proposed emissions guidelines in the NSPS OOOOb/EG OOOOc 2021 Proposal been adopted *and* implemented by all states as proposed. The EPA requests comment on other approaches that could be used to estimate the emissions

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[34] 42 U.S.C. 7436(f)(A)(ii) (requiring a determination by the Administrator that "compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by [the 2021 proposal]".)

reductions from CAA section 111(d) facilities had the NSPS OOOOb/EG OOOOc 2021 Proposal been finalized and implemented.

The EPA also recognizes that in the proposed approach for the equivalency determination, analysis of the reductions from CAA section 111(d) facilities under the NSPS OOOOb/EG OOOOc 2021 Proposal would be based on universal adoption of the presumptive standards in the proposed emissions guidelines, while analysis of the reductions achieved by state and Federal plans developed pursuant to the final EG OOOOc would account for any states' use of the RULOF provision to set less stringent standards. The EPA believes the proposed approach of assessing the reductions achieved by final state and Federal plans is aligned with the statutory text and Congressional intent. CAA section 136(f)(6)(A)(ii) states that the point of comparison for the emissions reductions that would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal are those resulting from "compliance with the requirements described in clause (i)." CAA section 136(f)(6)(A)(i) in turn refers to the "methane emissions standards and *plans* pursuant to subsections (b) and (d) of section 111." The EPA's proposed approach to use the reductions that will be achieved by approved state and Federal plans in the equivalency determination is based on the use of "plans" in CAA section 136(f)(6)(A)(i). Further, CAA section 136(f)(6)(A)(ii) establishes that EPA may not make the equivalency determination unless and until it can establish that "compliance with the requirements described in clause (i) *will result in equivalent or greater emissions reductions* as would be achieved by the [NSPS OOOOb/EG OOOOc 2021 Proposal]."[35] As similarly noted above, it is reasonable to infer from this language that Congress intended to guarantee that a minimum level of emissions reduction would be achieved by implementation of the CAA section 111 standards before the exemption became available – and because application of the RULOF provision may result in less stringent standards, Congress could not guarantee this minimum level would be achieved unless the equivalency determination considered the reductions actually achieved by the final

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[35] 42 U.S.C. 7436(f)(6)(A)(ii) (emphasis added).

NSPS and the standards actually set in state plans, including any standards set pursuant to the RULOF provision.

The EPA considered an approach which would compare the NSPS OOOOb/EG OOOOc 2021 Proposal, as proposed, with the final NSPS OOOOb/EG OOOOc as finalized but before implementation and consideration of RULOF, but ultimately rejected this approach. Although this approach would be relatively simple to apply, not taking into account the actual standards adopted in the state plans cannot lead to a sound conclusion about whether the emission reduction target that the statute sets will actually be met in practice. In other words, this approach could not guarantee that the "result" of implementation of the plans will be equivalent reductions, as the statute requires the EPA to determine. Further, CAA section 136(f)(6)(A)(ii) states that "compliance" with the standards should result in equivalent emissions reductions, but in practice, sources are not required to comply with the EG; instead, sources must comply with standards later established in state or federal plans. For these reasons, the EPA believes that comparing the NSPS OOOOb/EG OOOOc 2021 Proposal with the final NSPS OOOOb/EG OOOOc as finalized, but before implementation, is not as well aligned with the statutory text and intent of Congress. The EPA requests comment on its proposed approach and other approaches that could be used to estimate the emissions reductions that will be achieved by plans pursuant to CAA section 111(d), including comparing the NSPS OOOOb/EG OOOOc 2021 Proposal with the final NSPS OOOOb/EG OOOOc before implementation and consideration of RULOF.

The EPA reviewed comments on this topic submitted in response to the NSPS OOOOb/EG OOOOc 2022 Supplemental Proposal. Those comments informed the EPA's proposed approach and alternative approaches. While those comments were considered in the development of this proposal, because they were submitted in response to a separate rulemaking, any duplicative or additional comments on this topic must resubmitted in response to this proposal in order to be considered in the development of the final WEC rule.

e. Application of the Regulatory Compliance Exemption to Subpart W Facilities

CAA section 136(f)(6)(A) states: "[c]harges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111" upon an Administrator determination that "(i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities; and (ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the" NSPS OOOOb/EG OOOOc 2021 Proposal.

The EPA notes that an applicable facility in CAA section 136(d) is an entire site or collection of sites, each of which contains individual emissions sources. In contrast, the terms "affected facility"[36] and "designated facility"[37] are used by the EPA in the NSPS and EG regulations, respectively, to refer to an individual emissions source or a group of emissions sources at a site (*e.g.*, a storage tank battery or a collection of pneumatic controllers) to which a standard applies. A single subpart W facility may contain hundreds or thousands of CAA section 111(b) and (d) facilities. The EPA proposes to interpret and implement the regulatory compliance exemption such that an applicable subpart W facility that contains any CAA section 111(b) or (d) facilities would be eligible for the exemption once all other criteria are met (*i.e.*, the Administrator determinations and proposed compliance elements in 40 CFR 99.40). Table 3 shows the subpart W industry segments applicable to the WEC that may contain CAA section 111(b) or (d) facilities. WEC applicable facilities in the offshore production, LNG storage, LNG import and export, and transmission pipeline industry segments do not contain CAA section 111(b) or (d) facilities under the Crude Oil & Natural Gas source category (or any other source category in 40 CFR part 60) and would not be eligible for the regulatory compliance exemption.

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[36] "Affected facility" is defined for purposes of an NSPS at 40 CFR 60.2 to mean "with reference to a stationary source, any apparatus to which a standard is applicable."

[37] "Designated facility" is defined for purposes of an EG at 40 CFR 60.21a to mean "any existing facility. . . which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility."

The EPA proposes that if any future NSPS/EG rules are finalized such that additional industry segments contain CAA section 111(b) or (d) facilities, the WEC applicable facilities in those segments would be eligible for the regulatory compliance exemption.

Table 3. Subpart W Industry Segment and CAA Section 111(b) and (d) Facility Overlap

Subpart W Industry Segment Subject to WEC	**May contain CAA Section 111(b) and/or (d) Facilities?**
Onshore petroleum and natural gas production	Yes
Offshore petroleum and natural gas production	No
Onshore petroleum and natural gas gathering and boosting	Yes
Onshore natural gas processing	Yes
Onshore natural gas transmission compression	Yes
Onshore natural gas transmission pipeline	No
Underground natural gas storage	Yes
LNG import and export equipment	No
LNG storage	No

The EPA assessed other potential interpretations of the regulatory compliance exemption while developing the proposed approach. In particular, the EPA assessed an approach that would instead only exempt the emissions from individual CAA section 111(b) and (d) sources, rather than the emissions of the entire subpart W facility. For example, if certain pneumatic devices are regulated under NSPS OOOOb/EG OOOOc pursuant to CAA sections 111(b) and (d), all reported pneumatic device methane emissions from a subpart W facility would be subtracted from that facility's reported emissions. Under this approach, only emission sources at subpart W facilities that are not also CAA section 111(b) and (d) facilities (*e.g.*, methane slip from engines) would be considered when determining if a facility was above or below the waste emissions threshold. While this approach would exempt emissions associated with individual CAA section 111(b) and (d) facilities that are in compliance with the standards, as anticipated by the language in CAA section 136(f)(6)(A), the EPA does not believe that this approach would be consistent with the other text in that provision that is clear that the exemption applies to the "applicable facility," which CAA section 136(d) defines as an entire subpart W facility. Further, we do not believe that it would be practical to implement the regulatory compliance exemption in this manner because the individual emissions source types in subpart W do not always align with the individual CAA section 111(b) and (d) facilities. Exempting methane emissions from individual subpart W source types that have a similar name as a CAA section 111(b) or (d) facility may exclude a broader or narrower scope of equipment or components and associated emissions than those subject to the NSPS OOOOb/EG OOOOc. Methane emissions from CAA section 111(b) or (d) facilities therefore cannot be directly subtracted from reported subpart W data.

We request comment on the proposed approach for applying the regulatory compliance exemption to subpart W facilities and the proposed interpretation of the relevant statutory text. We also request comment on extending the regulatory compliance exemption to facilities in industry segments not currently covered by NSPS OOOOb/EG OOOOc requirements, in the event that such regulations pursuant to CAA 111(b) and (d) are finalized in the future. We recognize that the proposed approach to exempt entire subpart W facilities results in the exemption of methane emissions from sources that are not subject to NSPS OOOOb/EG OOOOc. While we believe the proposed approach is the most consistent with the language in CAA section 136(f)(6), we request comment on alternative interpretations.

f. Determining Eligibility With Respect to CAA Section 136(f)(6)(A)

It is expected that for many WEC applicable facilities, implementing NSPS OOOOb/EG OOOOc requirements would reduce methane emissions to levels below the waste emissions thresholds. The EPA interprets the regulatory compliance exemption as intending to provide relief from the WEC for WEC applicable facilities that remain above the waste emissions threshold even when their constituent CAA section 111(b) and (d) facilities (i.e. emissions sources) are in full compliance with their applicable methane emissions requirements. This structure provides a further incentive for compliance with applicable requirements.

The EPA proposes that the regulatory compliance exemption would only be available to WEC applicable facilities that exceed the waste emissions threshold. CAA section 136(f)(6)(A) states that “charges shall not be imposed pursuant to subsection (c) on an applicable facility” that meets the requirements of the regulatory compliance exemption. Subsection (c) in turn states that a charge shall be collected “on methane emissions that exceed an applicable waste emissions threshold.” Based on a plain reading of the statutory text, the EPA proposes that the exemption would not apply to WEC applicable facilities below the waste emissions threshold. Further, providing the exemption to WEC applicable facilities below the waste emissions threshold would serve no purpose as these facilities would not have positive WEC applicable emissions and therefore would not benefit from the exemption. Excluding facilities below the waste emissions threshold from the exemption would also reduce the reporting burden for those facilities, which would not be required to report information related to CAA section 111(b) and (d) compliance status.

As discussed in this section, CAA section 136(f)(6)(A) does not specify the definition of compliance for the purposes of the exemption, and many different types of compliance deviations or violations can occur. The EPA is therefore proposing what actions constitute compliance with a methane emissions requirement, pursuant to CAA section 136(f)(A), for the purposes of implementing the regulatory compliance exemption. The EPA’s proposed approach is intended to provide a clear threshold for establishing compliance status and eligibility for the exemption while minimizing the burden on industry and facilitating ease of implementation. The EPA is also proposing related reporting requirements for WEC applicable facilities that are necessary to implement the regulatory compliance exemption (see section II.D.2.g. of this preamble).

CAA section 136(f)(6)(A) states that the WEC shall not be imposed “on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111.” For the purpose of determining WEC facility eligibility for the regulatory compliance exemption, the EPA proposes that the compliance status of CAA section 111(b) and (d) facilities contained within a WEC applicable facility would be assessed based on compliance with the applicable methane emissions requirements for the Oil & Natural Gas Source Category (40 CFR part 60, subparts OOOOa, OOOOb, and OOOOc).

Further, the EPA proposes that should additional NSPS/EG regulations for the oil and natural gas industry source category be finalized in the future, compliance with the methane emissions requirements in those regulations would be assessed for determining eligibility for the regulatory compliance exemption. As discussed in section II.D.2.h. of this preamble, the regulatory compliance exemption could become unavailable if future NSPS/EG revisions result in a situation such that those revisions, upon implementation, result in fewer emissions reductions than achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal, had that proposal been finalized and implemented. Similarly, the exemption could be reinstated upon adoption and implementation of NSPS/EG revisions that restore emissions reduction equivalency with, or improvement upon, the NSPS OOOOb/EG OOOOc 2021 proposal. In such cases where a future NSPS/EG rule only applies to equipment in a segment of the oil and natural gas industry not covered by an existing NSPS/EG rule, the EPA proposes that any WEC applicable facilities with existing access to the regulatory compliance exemption would maintain that access. In other words, the “all states” requirement in CAA section 136(f)(6)(A)(i) would be assessed separately for the additional equipment covered by the new NSPS/EG, and any existing access to the exemption would not be lost while the determination is being made that CAA section 111(d) plans pursuant to the new EG rule were approved and in effect.

The EPA requests comment on its proposed approach for how NSPS OOOOa, NSPS OOOOb, and EG OOOOc should be considered for the purposes of the regulatory compliance exemption. The EPA also requests comment on its proposed approach in light of any potential future NSPS/EG rules for the oil and natural gas industry source category, or any other additional source category that might cover emissions sources at a WEC affected facility, and the role of any such future methane emissions requirements in determining eligibility for the regulatory compliance exemption.

The EPA proposes that any WEC applicable facility that contains CAA section 111(b) or (d) facilities would receive the regulatory compliance exemption if each of the CAA section 111(b) and (d) facilities that constitute the WEC applicable facility has no deviations or violations of the methane emissions requirements promulgated pursuant to the applicable NSPS or EG-implementing state and Federal plans. The EPA is proposing that this compliance requirement would apply for each CAA section 111(b) or (d) facility for each reporting year for the WEC applicable facility. For example, if all CAA section 111(b) or (d) facilities contained in a WEC applicable facility were in compliance with the applicable methane emissions requirements during a particular reporting year, the regulatory exemption would apply for that reporting year. If any CAA section 111(b) or (d) facilities contained in a WEC applicable facility in the respective reporting year were not in compliance with emissions requirements, the regulatory exemption would not apply for that reporting year. The EPA proposes that if a WEC applicable facility were to lose access to the regulatory compliance exemption in a reporting year due to a deviation or violation in that reporting year, it would be able to receive the exemption in any subsequent reporting year if there were no deviations or violations in that applicable reporting year.

The EPA is proposing that a WEC applicable facility would not be eligible for the regulatory compliance exemption if any CAA section 111(b) or (d) facility that is contained within the WEC applicable facility has one or more deviations or one or more violations of any methane emissions requirement under the applicable NSPS or state or Federal plan issued pursuant to the EG. The EPA recognizes that there are many potential elements to compliance with the methane requirements promulgated under CAA sections 111(b) and (d), such as compliance with a quantitative emissions limit and compliance with work practice standards, as well as multiple monitoring, recordkeeping, and reporting requirements. The EPA proposes to find that a deviation or violation from any of the methane requirements promulgated under CAA sections 111(b) and (d) constitutes non-compliance for purposes of the regulatory compliance exemption. The EPA believes that this approach is most consistent with the plain language of CAA section 136(f)(6)(A), which states that charges shall not be imposed on a facility that is "*subject to and in compliance with* methane emissions requirements pursuant to subsections (b) and (d) of section 111".[38] First, Congress made clear that it is not enough for a particular facility to be subject to methane regulations; each facility must also comply with those regulations. And in establishing what it means to comply, Congress did not employ any mitigating language. It is not enough to be "substantively" in compliance, for example, or "in compliance with all major requirements". Facilities must be "in compliance with requirements" pursuant to 111(b) and (d).

The EPA evaluated several alternative criteria for the regulatory compliance exemption eligibility. Another interpretation could be to apply a threshold, such as specific quantitative threshold requirements, for the regulatory compliance exemption. For example, the EPA might specify that a WEC applicable facility would still be deemed to be in compliance for purposes of the regulatory compliance exemption where the number of deviations or violations, or a quantity of excess emissions, fall below a specified threshold, as applied for all the CAA section 111(b) and (d) facilities contained in a WEC applicable facility. However, for the reasons discussed in the following paragraph, the EPA is not proposing this alternative.

Deviations from or violations of any compliance requirements can vary significantly in severity and impact, as well as frequency. For example, a WEC applicable facility could contain many CAA section 111(b) and (d) facilities with numerous deviations that, even collectively, result in a small amount of excess emissions. Another WEC applicable facility could contain a single CAA section 111(b) or (d) facility with a single deviation or violation that resulted in methane emissions significantly exceeding those that would have resulted had the CAA section 111(b) or (d) facility been in compliance with its methane emissions requirements. Violations of the emission standards are not the only violations that may be significant. Violations of monitoring requirements can be very serious, given that failure to do monitoring, or doing it

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[38] 42 U.S.C. 7436(f)(6)(A).

incorrectly, can result in significant emissions not being discovered or corrected. Reporting violations can also be very serious, if they result in government being unaware of significant problems and thus unable to address them. For these and many other reasons, there is often no easy way to determine the seriousness of particular violations without fact specific and resource intensive investigation. Given that deviations from and violations of requirements for emission standards under CAA section 111(b) and of state or Federal plan requirements under CAA section 111(d) can vary in type, severity, and frequency, and given that CAA section 136(f)(A) does not further specify what constitutes compliance for the purpose of the regulatory compliance exemption, the EPA is not proposing a specific quantitative threshold requirement for the regulatory compliance exemption (*e.g.*, number of violations or quantity of excess emissions).

Because under the statute the availability of the regulatory compliance exemption requires two threshold findings, including that all plans are approved and in effect, the exemption would not be available until several years after finalization of the WEC rule. See the discussion in section II.D.2.b of this preamble regarding the proposed approach for timing of the regulatory compliance exemption availability. With the exception of several sources (*e.g.*, combustion emissions for certain industry segments), most methane emission sources in covered industry segments required to report emissions under subpart W would also be subject to the CAA section 111(b) or (d) methane requirements promulgated in the final NSPS OOOOb and the plans issued and approved under EG OOOOc. The EPA expects that, as oil and gas operations implement the requirements of final NSPS OOOOb and the plans issued and approved pursuant to EG OOOOc (and undertake other methane mitigation voluntarily or due to other Federal or state regulations), total reported subpart W facility methane emissions would decline.

For many WEC applicable facilities, if the CAA section 111(b) and (d) facilities contained within a WEC applicable facility are in compliance with methane requirements promulgated under CAA sections 111(b) and (d), the WEC applicable facility would likely be below the waste emissions threshold. The Agency therefore expects that even if CAA section 111(b) or (d) facilities within these WEC applicable facility have compliance deviations, these WEC applicable facilities will likely remain below the waste emissions thresholds. In the alternative, the EPA expects that cases of significant or widespread compliance deviations or violations with the requirements promulgated under CAA section 111(b) or (d) could result in emission levels for a WEC applicable facility that could exceed the waste emissions thresholds. Because many WEC applicable facilities are expected to be below the waste emissions threshold when the regulatory compliance exemption becomes available, the EPA expects that deviations or violations will not have a significant impact for these facilities – they would not be eligible for the exemption not only because they are out of compliance, but also because they are below the waste emissions threshold, and there is no charge to exempt in that case.

The EPA requests comment on the proposed provisions for determining "compliance" for the purposes of the regulatory compliance exemption and the alternative approaches the agency considered. The EPA requests comment on specific criteria (*e.g.*, types of deviations or violations, quantitative thresholds) that could be applied to determine compliance with methane emissions requirements promulgated under CAA sections 111(b) and (d) for the purpose of assessing WEC applicable facility eligibility for the regulatory compliance exemption. The EPA requests comment on whether the criteria should consider whether the deviation or violation resulted in excess emissions, as demonstrated by monitoring and other data. The EPA also requests comment on excluding WEC applicable facilities below the waste emissions threshold from the regulatory compliance exemption.

g. Reporting and Recordkeeping Requirements for the Regulatory Compliance Exemption

We are proposing a reporting requirement at 40 CFR 99.7(b)(2)(iv) that would require that once the Administrator has made a determination that the requirements in CAA section 136(f)(6)(A) have been met, information related to the regulatory compliance exemption must be included in the WEC filing submitted by the WEC obligated party for each WEC applicable facility exceeding the waste emissions threshold that contains any CAA section 111(b) and (d) affected facilities. CAA section 136(f)(6)(A) mandates that the EPA shall not impose a charge upon WEC applicable facilities that qualify for the regulatory compliance exemption. The proposed approach for implementing the regulatory compliance exemption would make facilities that are below the waste emissions threshold ineligible for the exemption. The EPA therefore proposes that WEC obligated parties would not be required to report information related to the compliance status of CAA section 111(b) and (d) facilities contained within WEC applicable facilities for WEC applicable facilities that are below the waste emissions threshold.

The reporting requirements for facilities with the regulatory compliance exemption are proposed at 40 CFR 99.42. We are proposing that the filing would include a representation of the NSPS and state and Federal plan compliance status for each CAA section 111(b) and (d) facility located within a WEC applicable facility during the reporting year. This representation of compliance status would indicate whether the facility was in full compliance for the entirety of the reporting year (*i.e.,* for each CAA section 111(b) and (d) facility, there were no violations or deviations), or whether there were one or more deviations or violations during the reporting year. For facilities that meet all eligibility requirements for the exemption, we are proposing to require reporting of the ICIS-AIR ID (or if unavailable, the facility registry service (FRS) ID and EPA Registry ID from CEDRI) reporting identifiers for each CAA section 111(b) and (d) facility located at the WEC applicable facility. These identifiers are information necessary for the EPA to assess the accuracy of the representation of compliance status through linkages to reports and emissions and compliance data for each CAA section 111(b) and (d) facility located at the WEC applicable facility.

As supporting documentation for the representation of compliance status of WEC applicable facilities that are eligible for the exemption but were not in full compliance for the entirety of the reporting year, we are proposing to require the submittal of one report associated with the CAA section 111(b) and (d) facilities located within the WEC applicable facility that documents a deviation or violation during the reporting year. As supporting documentation for the representation of compliance status of WEC applicable facilities that are eligible for the exemption and that were in full compliance for the entirety of the reporting year, we are proposing to require the submittal of report(s) associated with the CAA section 111(b) and (d) facilities located within the WEC applicable facility. The EPA recognizes that the compliance certification period for CAA section 111(b) and (d) facilities may not align with the reporting year for which the filing is being completed and that at the time of the WEC filing due on March 31 of each year, report(s) covering the complete preceding reporting year for WEC filing may not be available. To accommodate for these cases where a report is not available for the complete reporting year of WEC filing, the EPA is proposing that the WEC obligated party would provide the report, if available, that covers a portion of the year, identify the period of time covered by the report, and for the remainder of the year provide a representation of compliance status for each CAA section 111(b) and (d) facility at the WEC applicable facility that is not included in the submitted report. It also is possible that the complete calendar year of WEC filing is covered by two annual reports, each covering a portion of the calendar year. In this case, the WEC applicable facility should submit both annual reports. The EPA further recognizes that a WEC applicable facility may contain CAA section 111(b) and (d) facilities that first became subject to requirements under CAA sections 111(b) and (d) during the reporting year associated with the filing and for which the first year of compliance is not completed. For these CAA section 111(b) and (d) facilities, we are proposing to require that the filing identify the type of facility, that date that it became subject, and a representation of the compliance status for the portion of the year in which it was subject to requirements under CAA sections 111(b) and (d). In cases where the initial filing does not include a report covering the entire reporting year, we are proposing to require that the WEC obligated party provide a revised filing once such a report becomes available. The EPA is proposing that this revised filing under the WEC rule would be required to be made on or before the date that the compliance report covering the remainder of the year would be due under the applicable requirements of CAA section 111(b) or (d). The deadlines for filing revisions to WEC filings as discussed in section III.A.4. do not apply for the submittal of compliance reports.

The EPA requires this information for the verification of exemption eligibility. Reported information will be used to conduct verification as discussed in section III.A.4., and reported information, records and other information as applicable will be used to conduct any auditing that occurs under section III.E.1.

The EPA is aware that this proposed reporting program may result in cases where a WEC obligated party makes a good-faith representation that each CAA section 111(b) and (d) facility at the WEC applicable facility is in compliance but later independently discovers the existence of one or more deviations or violations. In this proposed rulemaking, such independent discoveries would be considered to be substantive errors within the WEC filing. Proposed 40 CFR 99.7(e)(1) would require submittal of a revised WEC filing within 45 days of the discovery that a previously submitted WEC filing contains a substantive error. Provided that timely submittal of a revised filing is made, if a revised regulatory compliance exemption filing results in the imposition of WEC obligation from a WEC applicable facility that previously qualified for exemption, we are proposing that the WEC obligated party would not be subject to interest penalties normally assessed for payments made after March 31, as discussed in section III.B.1. of this preamble.

However, later discoveries of deviations or violations by the EPA or another regulatory authority, or discoveries as a result of investigation by the EPA or another regulatory authority (including information requests), are not treated the same way as errors. Where a WEC obligated party represents that each CAA section 111(b) and (d) facility at the WEC applicable facility is in compliance, but the EPA or another regulatory authority subsequently discovers the existence of one or more deviations or violations, or the CAA section 111(b) and (d) facility identifies the deviation or violation as a result of an EPA investigation (including information requests), the

WEC obligated party may be subject to enforcement and required to pay any outstanding WEC fees and interest penalties. False statements may be subject to criminal enforcement.

The EPA seeks comment on the reporting and recordkeeping requirements for the regulatory compliance exemption. We seek comment on whether additional information should be collected or retained to allow for verification of eligibility for the exemption.

h. Resumption of WEC Under CAA Section 136(f)(6)(B)

CAA section 136(f)(6)(B) states that if, at any point after the Administrator has made the determination required by CAA section 136(f)(6)(A), the conditions for such determination are no longer met, the regulatory compliance exemption ceases to apply. Because the EPA proposes to determine that the regulatory compliance exemption is only available if *all states* are subject to standards and plans pursuant to CAA sections 111(b) and (d) that are, collectively, equivalent to the NSPS OOOOb/EG OOOOc 2021 Proposal, the EPA proposes that all WEC applicable facilities would lose access to the exemption if either of the conditions in CAA section 136(f)(6)(A) ceased to apply. For example, if a state plan were legally challenged and vacated after the initial determination, plans would no longer be approved and in effect in all states, and the regulatory compliance exemption would no longer be available. Similarly, if after the initial equivalency determination methane emissions requirements promulgated under CAA section 111(b) or (d) were modified such that they no longer resulted in equivalent or greater aggregate emissions reductions than the NSPS OOOOb/EG OOOOc 2021 Proposal, the exemption would no longer be available. Note that in addition to future revisions to EG, revisions to the requirements in individual state plans pursuant to CAA section 111(d) could also result in a situation in which implementation of the final NSPS and state or federal plans does not achieve equivalent or greater emissions reductions compared to the 2021 NSPS OOOOb/EG OOOOc Proposal. (The conditions under which an individual WEC applicable facility would receive or become ineligible for the regulatory compliance exemption while the conditions in CAA section 136(f)(6)(A) are still met are discussed in section II.D.2.f. of this preamble.) The EPA proposes that any determination that the criteria in CAA section 136(f)(6)(A) are no longer met after the initial determination would be made through a future administrative action. The EPA proposes that access to the exemption would be lost for the full calendar year in which the required criteria were no longer met. The EPA proposes that if access to the regulatory compliance exemption were lost after it was initially made available because one of the two required conditions in CAA section 136(f)(6)(A) were no longer met, it could become available again following a subsequent determination that both conditions were once again achieved. Under such circumstances, the exemption would become available again for the reporting year in which the conditions were met. The EPA proposes that if the conditions ceased to apply and were then met again in the same reporting year, the exemption would be available for the entire reporting year. The EPA requests comment on alternative approaches that would revoke the regulatory compliance exemption for a portion of the year in which the requirements were no longer met and how data under such an approach could be pro-rated for the purposes of determining WEC. The EPA requests comment on the proposed implementation of CAA section 136(f)(6)(B). While the EPA believes the proposed implementation of CAA section 136(f)(6)(B) is consistent with a plain reading of the statutory text and consistent with the proposed timing of the regulatory compliance determinations under CAA section 136(f)(6)(A) (*i.e.*, methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in *all States*), the agency requests comment on an approach in which access to the exemption would be lost at a state-by-state level. In this alternative approach, if circumstances occurred such that a state plan was no longer approved and in effect, only the WEC applicable facilities located in that state would lose access to the exemption; for WEC applicable facilities that span multiple states, access would be lost if the state plan for any of the states in which the WEC applicable facility is located were no longer approved and in effect.

3. Plugged Well Exemption Under CAA Section 136(f)(7)

Plugged wells have lower methane emissions than active wells and unplugged inactive wells; therefore, plugging wells will reduce total facility emissions potentially subject to WEC. Congress created an incentive for plugging and permanently shutting wells by including an exemption from the WEC in CAA section 136(f)(7): "[c]harges shall not be imposed with respect to the emissions rate from any well that has been permanently shut-in and plugged in the previous year in accordance with all applicable closure requirements, as determined by the Administrator.". Separately, in CAA section 136(a)(3)(D) and 136(b), Congress provided funding that can assist owners and operators who elect to voluntarily and permanently shut in and plug wells on non-Federal land.[39]

In this rule, we are proposing that this exemption would be applicable to wells in the onshore and offshore petroleum and natural gas production industry segments. We interpret this exemption to apply to the production industry segments only and not to wells in other segments, such as storage wells. Production wells are distinctly different in purpose and emissions profile than underground storage wells, which are generally replaced with new storage wells then they are plugged and abandoned. We seek comment on including wells in the underground natural gas storage industry segment under this exemption. We are proposing that in the WEC filing, exempted emissions would be those from wells permanently shut-in and plugged in the previous year (*i.e.*, if a well is permanently shut-in and plugged in 2026, the exempted emissions would be deducted from the 2026 emissions totals that are filed under WEC in 2027).

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[39] On August 30, 2023, the EPA, U.S. Department of Energy, and National Energy Technology Laboratory announced the availability of up to $350 million in formula grant funding to eligible states to help monitor and reduce methane emissions from marginal conventional wells, including to help owners and operators voluntarily and permanently reduce methane emissions from marginal conventional wells. Inflation Reduction Act (IRA) – Mitigating Emissions from Marginal Conventional Wells, Funding Opportunity Number DE-FOA-003109, available at: *https://www.grants.gov/web/grants/view-opportunity.html?oppId=350045*.

a. Determining if the Exemption for Permanently Shut-In and Plugged Wells Applies to a WEC Applicable Facility

The EPA is proposing two criteria for determining if the exemption for permanently shut-in and plugged wells applies to a WEC applicable facility.

Consistent with the other exemptions, the first criterion is that the facility must have emissions that exceed the waste emissions threshold. CAA 136(c)(7) notes that “charges shall not be imposed” on emissions from permanently shut-in and plugged wells. Charges would not be imposed on emissions below the threshold and therefore an exemption is unnecessary in cases where facility emissions are below the threshold. The EPA proposes that emissions from facilities that are below the waste emissions threshold would not be exempted. The EPA proposes that for facilities that exceed the waste emissions threshold, emissions eligible for the plugged well exemption could be subtracted up to the point where facility emissions equal the waste emissions threshold (*i.e.*, the lowest possible WEC applicable emissions for a facility with the plugged well exemption would be zero).

Second, wells must meet the following definition of permanently shut-in and plugged in accordance with all applicable closure requirements. The EPA proposes that for the purposes of this exemption, a permanently shut-in and plugged well is one that has been permanently sealed to prevent any potential future leakage of oil, gas, or formation water into shallow sources of potable water, onto the surface, or into the atmosphere. For the purposes of this exemption, the EPA is proposing that a well would be considered to be permanently shut-in and plugged, in accordance with all applicable closure requirements, if the owner or operator has met all applicable Federal, state, and local requirements for closure in the jurisdiction where the well is located. For the purposes of this exemption, we are proposing that a well would be considered permanently shut-in and plugged on the date a metal plate or cap has been welded or cemented onto the casing end.

Section II.D.3.c. below details the reporting requirements for this exemption which provide information necessary for verification of the exemption eligibility and exempted emission quantities.

In addition to requirements specifying how to plug a well, relevant Federal, state, and local requirements often also specify requirements such as for notifications, reporting, and site remediation. For purposes of 40 CFR part 99, we propose that the applicable closure requirements would include only the requirements specific to well plugging. We are not proposing to include requirements for notifications, reporting, and site remediation as part of the exemption eligibility criteria for following "all applicable closure requirements" because the closure of the well is the key activity impacting methane emissions, which is the focus of the WEC, and these other aspects of closure are less relevant to methane emissions levels. We also note that had we proposed to include these additional requirements in our interpretation of "all applicable closure requirements," the reporting requirements would increase for permanently shut-in and plugged wells and this may lead to recalculations of WEC years after the exemption was initially applied. We request comment on whether "all applicable closure requirements" should instead be interpreted to include notifications, reporting, site remediation and other post-closure activities at plugged well.

b. Calculations of Exempted Emissions from Permanently Shut-In and Plugged Wells

The EPA proposes that the methane emissions eligible for the exemption are those that occur at the well level including those from wellhead equipment leaks, liquids unloading, and workovers with and without hydraulic fracturing in the reporting year in which the well was plugged. We are proposing to only consider these emissions sources in the calculation of exempted emissions for the permanently shut-in and plugged well as we expect use of production-related equipment or equipment associated with treating production streams generally (*e.g.*, AGRU, dehydrator, separator) to be at a minimum. We are proposing to limit the emissions quantity to the source types we expect to represent the most significant emissions share expected at permanently shut-in and plugged wells. We note that methane emissions in the reporting year from other equipment onsite (*e.g.*, separator, compressor, flare) may result from multiple wells and not just the wells that are plugged in the reporting year. We request comment on an interpretation that would exempt all methane emissions associated with the production from the permanently shut-in and plugged well – not limited to the wellhead equipment leaks, liquids unloading, and workovers as is included in this proposal – during the calendar year of closure, including the methodology by which methane emissions from non-wellhead specific sources in subpart W could be attributed to the permanently shut-in and plugged well.

For the purposes of quantifying the methane emissions from equipment leaks, liquids unloading, workovers with hydraulic fracturing, and workovers without hydraulic fracturing associated with each permanently shut-in and plugged well, we are proposing to use the methane emissions and throughput data collected or reported to subpart W of part 98. As discussed previously in this preamble, proposed amendments in the 2023 Subpart W Proposal impact the data available to best estimate the exempted emissions from the permanently shut-in and plugged well. Therefore, as described in more detail in this section, for applicable emission sources and industry segments, different approaches are proposed for certain time periods.

The current subpart W rule requires that onshore petroleum and natural gas production facilities report methane emissions from liquids unloading and workovers to be reported by sub-basin for each WEC applicable facility as well as methane emissions from equipment leaks at the facility-level. Subpart W of part 98 also currently requires offshore petroleum and natural gas production facilities and onshore petroleum and natural gas production facilities to report facility-level throughput of gas and oil handled or sent to sale, respectively. Proposed revisions included in the 2023 Subpart W Proposal would require onshore petroleum and natural gas production facilities to report additional elements that facilitate quantification of methane emissions from individual shut-in and plugged wells. Specifically, beginning in reporting year 2024, the 2023 Subpart W Proposal would require onshore petroleum and natural gas production facilities to report well-level throughput volumes for gas and oil sent to sale from wells that are permanently shut-in and plugged. Additionally, beginning in reporting year 2025, the 2023 Subpart W Proposal would increase the granularity of methane emissions reporting for liquids unloading and workovers to the well-level and methane emissions reporting for equipment leaks to the well pad level. Due to the differences in available reporting data for 2024 and future years, the proposed approach for quantifying methane emissions in part 99 for individual wells located at onshore petroleum and natural gas production facilities that are permanently shut-in and plugged in 2024 would be different than the proposed approach for quantifying methane emissions from wells located at onshore petroleum and natural gas production facilities that are permanently shut-in and plugged in 2025 and future years.

For reporting year 2024, the EPA proposes through 40 CFR 99.52 that WEC applicable facilities in the onshore petroleum and natural gas industry segment would quantify methane emissions from permanently shut-in and plugged wells by allocating the subpart W of part 98 reported facility-level equipment leak, liquids unloading, and workover methane emissions using subpart W of part 98 reported production volumes of gas and oil sent to sale. We are proposing that WEC applicable facilities in the onshore petroleum and natural gas industry segment would sum the total subpart W of part 98 reported methane emissions from equipment leaks, liquids unloading, and workovers, and multiply the sum of the methane emissions by the ratio of subpart W of part 98 reported production at the permanently shut-in and plugged well to the subpart W of part 98 reported facility-level total production.

For facilities with only gas production with exempt plugged well emissions, we are proposing that the reported gas produced from the plugged wells be divided by the total gas production at the facility to develop the ratio. For facilities with only oil production with exempt plugged well emissions, we are proposing that the reported oil produced from the plugged wells be divided by the total oil production at the facility to develop the ratio. For facilities with both gas and oil production with exempt plugged well emissions, we are proposing that gas production that is reported to subpart W of part 98 by the WEC applicable facility in the onshore petroleum and natural gas industry segment would be converted to barrels of oil equivalent using a default value of 6,000 scf/barrel, such that throughput volumes will be on the same basis for facilities that report production of gas and oil. We are seeking comment on whether the EPA should provide an option for WEC applicable facilities to use a facility-specific value for barrels of oil equivalent, including whether facilities routinely determine this value and whether significant variability is expected in this value.

For 2025 and future years, we are proposing that WEC applicable facilities in the onshore petroleum and natural gas industry segment would estimate well-level emissions in accordance with part 98 methods for the permanently shut-in and plugged well. As described previously, for 2025 and future years, subpart W of part 98 would require reporting of methane emissions from liquids unloading and workovers to be at the well-level for facilities in the onshore petroleum and natural gas industry segment, therefore we are proposing that facilities in the onshore petroleum and natural gas industry segment would utilize the methane emissions as -reported to subpart W part 98 in their part 99 exemption calculation for these emissions sources. Also, as described previously, for 2025 and future years, subpart W of part 98 would require reporting of methane emissions from equipment leaks at the well pad for facilities in the onshore petroleum and natural gas industry segment. In order to obtain a well-level estimate for the part 99 exemption calculation, we are proposing to require facilities in the onshore petroleum and natural gas industry segment to utilize the subpart W of part 98 input data and emission estimation methods for wellhead equipment leaks to calculate the methane emissions at the well level for the permanently shut-in and plugged well. For example, if the equipment leak methane emissions at the well pad that includes the permanently shut-in and plugged well were estimated using the leaker method in 40 CFR 98.233(q), the WEC applicable facility would use the count of leakers by component type (*e.g.*, valve, connector) recorded for the permanently shut-in and plugged well, the operating time of the well during the year, and the appropriate emissions factors from subpart W of part 98 to estimate the methane emissions from the permanently shut-in and plugged well. Similarly, if the equipment leak methane emissions at the well pad that includes the permanently shut-in and plugged well were estimated using the population count method in 40 CFR 98.233(q), the WEC applicable facility would use the operating time of the well during the year and the appropriate emissions factors from subpart W of part 98 to estimate the emissions from the permanently shut-in and plugged well.

For offshore petroleum and natural gas production facilities, the current subpart W of part 98 reporting requirements are based on the facility's submission to the Bureau of Ocean Energy Management (BOEM), which includes methane emissions for component-level equipment leaks. The methane emissions required to be reported by offshore facilities would be unchanged by the 2023 Subpart W Proposal as it pertains to this exemption in that these facilities will continue to report the data from their BOEM report. Subpart W of part 98 also currently requires offshore petroleum and natural gas production facilities to report facility-level throughput of gas and oil handled in the reporting year. Proposed revisions included in the 2023 Subpart W Proposal for offshore petroleum and natural gas production facilities would add requirements for the reporting of well-level throughput volumes for gas and oil sent to sale from wells that are permanently shut-in and plugged beginning in reporting year 2024. The 2023 Subpart W Proposal would also revise the terms in the current reporting elements for facility-level throughputs to refer to gas sent to sale, rather than handled, for consistency with the CAA language and with the onshore production industry segment. As noted in the preamble for the 2023 Subpart W Proposal, these verbiage changes for facility-level throughput are not expected to impact the quantity of production volumes reported and were made for consistency and clarity. For the purposes of estimating the exempted emissions for permanently shut-in and plugged wells at offshore petroleum and natural gas production facilities, we are proposing that facilities allocate the component level equipment leaks (*i.e.*, those from valves, connectors) reported to subpart W of part 98 by the ratio of production from the well that has been permanently shut-in and plugged to the total facility-level production. Analogous to the approach for onshore petroleum and natural gas production facilities for reporting year 2024, we are proposing that gas sent to sale be converted to BOE using a default value of 6,000 scf/bbl BOE.

For all reporting years and applicable industry segments, if the WEC applicable facility has more than one permanently shut-in and plugged well, we are proposing that the part 99 emissions calculations would be performed for each well and summed to determine the net annual quantity of methane emissions at the WEC applicable facility eligible for the exemption.

c. Reporting and Recordkeeping Requirements for the Exemption for Permanently Shut-In and Plugged Wells

Through the provisions proposed at 40 CFR 99.51, the EPA is proposing that the WEC obligated party receiving the exemption would provide for each well at a WEC applicable facility, the well ID number as reported to subpart W of part 98; the date the well was permanently shut-in and plugged; the statutory citation for each state, local, and Federal regulation stipulating requirements that were applicable to the closure of the permanently shut-in and plugged well; the emission attributable to the well, and for each WEC applicable facility, the total emissions attributable to all permanently shut-in and plugged wells at the facility; and a certification statement by the designated representative for the WEC obligated party that all identified wells were closed in accordance with state, local, and Federal requirements. We are proposing that the information included in the report would be subject to the general recordkeeping requirements for part 99, meaning these records must be retained for 5 years following the WEC filing year of the exemption such that they can be made available to the EPA for inspection and review.

The EPA requires this information for the verification of exemption eligibility and of exempted emission quantity. Reported information will be used to conduct verification as discussed in section III.A.4., and reported information, records and other information as applicable will be used to conduct any auditing that occurs under section III.E.1.

The EPA seeks comment on the reporting and recordkeeping requirements for the exemption for emissions from wells that are permanently shut-in and plugged. We seek comment on whether additional information should be collected or retained to allow for verification of the quantity of emissions eligible for the exemption.

III. General Requirements of the Proposed Rule

A. WEC Reporting Requirements

1. Required Reporters

The WEC obligated party would be required to submit a WEC filing annually by March 31 that would include data collected from each WEC applicable facility of which it (the WEC obligated party) is comprised as of December 31 of each reporting year. The WEC filing would provide the data necessary for the EPA to assess and verify the WEC obligation including certain part 98 emissions information and netting, as applicable, as well as supporting documentation for any WEC applicable facility exemptions.

2. Reporting Deadlines

As required under the CAA sections 136(c) and (e), the assessment of the first WEC will be based on data collected under subpart W of the GHGRP beginning on January 1, 2024. We are proposing in 40 CFR 99.5 that the first WEC filing would be due March 31, 2025, and would be required to be submitted annually by March 31 thereafter, as applicable. We have proposed the March 31 reporting deadline under this action for the purpose of quantifying WEC such that the information reported for part 99 can be done in coordination with and on the same schedule as (*i.e.*, by March 31 of the calendar year following the reporting year) the information reported under subpart W.

The EPA is proposing that final revisions to the first WEC filing, with the exception of resubmissions to provide CAA section 111(b) or (d) compliance reports or revisions to previously reportd compliance reports for the purposes of the regulaltory compliance exemption, would be due by November 1, 2025, and would be required to be submitted annually by

November 1 thereafter, as applicable (see section III.A.4. of this preamble for discussion and request for comment on this deadline).

3. Submission of the WEC Filing

The EPA proposes that each WEC filing must be submitted electronically in accordance with the requirements of 40 CFR 99.6 and in a format specified by the Administrator.

As noted previously in this section of the preamble, the EPA proposes that each WEC obligated party will submit a WEC filing annually. The WEC filing content we are proposing is expected to provide the data necessary to complete the WEC calculations as described previously in the preamble. We are proposing WEC filing reporting requirements to cover general company information including physical address, email, telephone number, list of associated WEC applicable facilities and their identifying information (*e.g.*, part 98, subpart W e-GGRT ID), as well as the net WEC emissions calculated in accordance with 40 CFR 99.22 and the WEC obligation as calculated pursuant to 40 CFR 99.23. We are also proposing that each WEC obligated party's WEC filing include certain information at the WEC applicable facility level. Specifically, we are proposing that for each WEC applicable facility that comprises the WEC obligated party, the reporting requirements would cover facility-level information including the facility's eGGRT ID, the facility's industry segment(s), the facility's waste emissions threshold calculated in accordance with 40 CFR 99.20, and the facility's WEC applicable emissions calculated in accordance with 40 CFR 99.21.

The EPA seeks comment on these reporting and recordkeeping requirements (e.g., date of WEC filing and payment for the first year). We seek comment on whether additional information should be reported to EPA or retained by the WEC obligated party or WEC applicable facility to allow for verification of the WEC filing.

The EPA is also proposing reporting requirements for each WEC obligated party related to the three WEC exemptions, which are discussed in sections II.D.1. through 3. of this preamble. Under the proposed approach, the exemptions are only available to WEC applicable facilities that exceed the waste emissions threshold. The EPA therefore proposes that these reporting requirements would only apply to WEC applicable facilities that exceed the waste emissions threshold and are otherwise eligible for the exemption(s). The EPA seeks comment on the reporting requirements for each exemption, as noted in sections II.D.1. through 3. of this preamble.

4. Verification and WEC Filing Revisions

We anticipate that the foundation of the WEC obligated party's WEC filing would be the methane emissions and throughput reported by the WEC applicable facilities in their subpart W reports. As specified in § 98.3(f) and (h) of this chapter, part 98 currently includes a verification process and resubmission process for resolving substantive error(s)[40] in reporting. These errors are either found through self-discovery by the WEC obligated party or are found by the EPA during the verification process. In part 98, errors must be resolved within 45-days from discovery or notification of the error by the EPA. The EPA may grant a 30-day extension request if the request is timely, such that a total of 75 days may be provided for complete issue resolution. Additional extensions may be approved by the Administrator in specified limited circumstances. Resolution is either made by report revision and resubmission or by providing an adequate demonstration that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error. Upon satisfying these requirements, the EPA designates the part 98 report as verified. If the requirements in § 98.3 of this chapter are not satisfied, the EPA considers the part 98 report unverified.

We are proposing that the verification status of the WEC applicable facility with respect to the reporting in subpart W part 98 would be considered by the EPA when determining the verification status of the part 99 filing because the subpart W data would be the cornerstone of the WEC. In effect, a WEC filing may not achieve verified status until all errors associated

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[40] 40 CFR 98.3(h)(3): A substantive error is an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified.

subpart W reports that impact total WEC are corrected. For example, if the subpart W part 98 report of one WEC applicable facility contains errors related to reported emissions or throughput that affect total WEC, the EPA could by extension consider the WEC filing of the WEC obligated party that includes that WEC applicable facility to be unverified. However, there may also be situations in which an unverified subpart W part 98 report does not impact the ability to accurately calculate a WEC obligated party's WEC obligation. In these circumstances, the proposed approach would allow the EPA to verify a WEC obligated party's part 99 report even if the part 98 report of a WEC applicable facility associated with the WEC obligated party remained unverified.

Separately, there are elements of the part 99 filing that would not be tied to the subpart W report, such as the calculation of the WEC including netting and any exemption information. We are proposing to implement a similar verification procedure under part 99 to that which exists under part 98. In implementing the verification of information submitted under part 99, the EPA envisions a two-step process. First, we propose to conduct an initial centralized review of the data that would help assure the completeness and accuracy of data. Second, the EPA intends to notify WEC obligated parties of potential errors, discrepancies, or make inquiries as needed concerning the WEC filing. Specifically for this rulemaking, we anticipate that there could be errors or clarifications with respect to the supporting documentation and quantification of emissions associated with exemptions from the WEC, which may require EPA review to evaluate and confirm their validity and accuracy. The part 99 verification review would identify issues resulting from the calculation of WEC based on verified subpart W GHGRP reports and verified WEC filings to the extent possible. A thorough discussion of the separate process for unverified reports and approach for reassessment of WEC obligation due to resubmissions is discussed in section III.B. of this preamble.

We are proposing provisions that would require a WEC obligated party to resubmit their WEC filing within 45-days of either being contacted in writing by the EPA notifying them of the presence of a substantive error in their WEC filing or by self-discovering that a previously submitted WEC filing contains one or more substantive errors (except as described later in this section), or within 75 days if granted a 30-day extension per 40 CFR 99.7(e)(4). For the purposes of part 99, we are proposing to consider a substantive error to be an error that impacts the Administrator's ability to accurately calculate the WEC obligated party's obligation, which may include, but would not be not limited to, the list of WEC applicable facilities associated with a WEC obligated party and corresponding data reported in each listed WEC applicable facility part 98 report(s), emissions associated with exemptions, and supporting information for each exemption to demonstrate its validity. We are proposing that the revised WEC filing must correct all substantive errors or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error.

We are also proposing that if a WEC applicable facility revises and resubmits their part 98 report, which results in impacts on the WEC calculations, the WEC obligated party would also be required to submit a revised WEC filing that includes the number of corrections and information detailing the correction(s) made. In the event that a subpart W report revision results in a change in the applicability of part 99 to the facility, under the proposed provisions the WEC obligated party would either submit a WEC filing adding or removing any facilities, as appropriate. As described in the paragraph below, with the exception of resubmissions to provide CAA section 111(b) or (d) compliance reports or revisions to previously reported compliance reports for the purposes of the regulatory compliance exemption, the EPA is proposing that part 99 resubmissions would only be allowed up to November 1 of the year following the reporting year. Any part 98 resubmissions after this date that impact WEC calculations would not be required to be resubmitted in a revised WEC filing; facilities could continue to resubmit data under subpart W at any time. Resubmissions related to CAA section 111(b) or (d) compliance reports for the purposes of the regulatory compliance exemption must be made as discussed in section II.D.2.g. of this preamble.Under subpart W, facilities may resubmit data for historic reporting years via e-GGRT for the most recent five reporting years (e.g., submit updates to 2019 data in 2022). Data resubmission for historic reporting years in the context of the WEC program is extremely complicated due to the potential changes in facility ownership over time and the implications this has on netting of emissions from facilities under common ownership or control. For example, a company or a facility owned by a company in one year may be owned in whole or in part by one or multiple different companies the next year. With such changes occurring annually to multiple facilities across multiple owners and operators with more than one facility under common ownership or control, there is no practical means of incorporating resubmitted data for historic reporting years in the WEC program. This would require the EPA to engage in a potentially constant series of WEC recalculations and associated invoicing or refunds. The EPA therefore proposes a deadline of November 1 for each year, after which time no WEC filings could be resubmitted. For example, resubmissions of data initially reported by March 31, 2025, used to assess WEC for the 2024 reporting year, would be required to be submitted by November 1, 2025. This proposed approach would not allow resubmissions for historic reporting years for WEC filings, even if their corresponding subpart W data was resubmitted for historic reporting years for purposes of subpart W. Subpart W facilities would continue to be subject to part 98 existing requirements for resubmitting data for previous reporting years, but any data resubmitted under part 98 after November 1 of the calendar year following the respective reporting year would not be considered for the purposes of WEC under part 99. This deadline would apply to all WEC applicable facilities, including those with data verified by EPA. The EPA's proposed approaches for WEC filing requirements and data verification are intended to incentivize complete and accurate WEC filings under part 99, and thus corresponding reporting of complete and accurate data under part 98, by March 31 of each year. As a result, the EPA expects that there will be little need to resubmit data after this initial reporting deadline, and the seven months between March 31 and the proposed final deadline of November 1 would give facility owners or operators sufficient time to make any resubmissions. The EPA proposes that it would retain the right to reevaluate WEC obligations in WEC filings after November 1 (e.g., as part of an EPA audit of facility data). Similarly, the November 1 deadline would not apply to adjustments to WEC obligations resulting from the process to resolve unverified data, proposed at 40 CFR 99.8, should that resolution occur after November 1.

The EPA requests comment on the proposed approach of setting a deadline for WEC resubmissions under part 99 and in doing so not allowing data resubmissions for the WEC filing for previous historic reporting years. The EPA requests comment on the November 1 deadline and options for alternative deadlines. The EPA also requests comment on alternative approaches that would allow data resubmissions for historic reporting years under the WEC program, as well as comment on how such changes would be incorporated into netting for historic reporting years.

B. Remittance and Assessment of WEC

We are proposing that each WEC obligation payment must be submitted electronically in accordance with the proposed requirements of 40 CFR 99.6 and in a format specified by the Administrator as part of the submission of the WEC filing (*i.e.*, by March 31 each year covering the preceding reporting year).

For the purposes of ensuring timely payment of the WEC, the EPA is proposing financial sanctions under 40 CFR 99.10 of subpart A, pursuant to the authority included in the Federal claims provision at 31 U.S.C. 3717. These penalties would apply to delinquent WEC payments. Under 31 U.S.C. 3717, there are interest, penalties, and costs that may be imposed on outstanding or delinquent debts arising under a claim owed by a person to the U.S. Government. Specifically, under 31 U.S.C. 3717(a)(1), agencies shall charge a minimum annual rate of intereston an outstanding debt on a United States Government claim owned by a person.[41] Under

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[41] This rate of interest is known as the Current Value of Funds Rate, or CVFR, and is published prior to November 30th of each year by Treasury. The CVFR is based on the weekly average of the Effective Federal Funds Rate, less 25 basis points, for the 12-month period ending September 30th of each year, rounded to the nearest whole percent. This rate may be revised on a quarterly basis if the annual average, on a moving basis, changes by 2 percentage points or more.

the EPA's implementing Policy Number 2540-9-P2, accounts are considered delinquent when the EPA does not receive payment by the due date specified on a bill or invoice (*i.e.*, for the WEC obligation at the time of submission of the WEC filing). The EPA is proposing to cite this Federal claims interest charge authority as the first tier of WEC payment sanctions.

Second, under 31 U.S.C. 3717(e)(1), agencies must collect an additional penalty charge of not more than six percent per year for failure to pay any part of a debt more than 90 days past due, as well as additional charge to cover the cost of processing delinquent claims. Under Policy Number 2540-9-P2, the EPA Finance Centers are responsible for issuing demand notices and conducting collection efforts for the Agency. The EPA Finance Centers would assess interest, handling, and penalty charges in 30-day increments for late payments and would assess the 6 percent penalty with the 3rd demand letter or notice.

The EPA therefore proposes to include this additional 6 percent non-payment penalty charge for WEC debts that are more than 90 days past due. This would be the second tier of sanction authority under this proposal's set of payment sanctions and would be implemented if the first tier of interest charges is not effective in causing a delinquent WEC obligated party to make their payments current. The EPA seeks comment on its proposed approach for applying interest to late WEC fee payments.

Additionally, for WEC obligated parties that fail to submit their annual WEC filing by the deadline discussed in section III.A.2. of this preamble, the EPA is proposing a daily penalty no greater than the rate associated with 42 U.S.C. 7413(d)(1) specified in Table 1 of 40 CFR 19.4, as amended. The EPA Finance Centers would assess interest, handling, and penalty charges in 30-day increments. We are proposing that the assessment of this penalty would begin on the date that the WEC filing was considered past due (*i.e.,* April 1st) and continue until such time that the WEC filing is submitted and certified by the WEC obligated party. The EPA requests comment on its proposed approach of establishing a daily penalty for unsubmitted WEC filings.

1. Process for Reassessing WEC for WEC Filings Resubmitted After the Initial Waste Emission Charge Has Been Assessed

As discussed in section III.A.4. of this preamble, WEC obligated parties may need to resubmit their WEC filings and WEC applicable facilities may need to resubmit their GHGRP reports. These resubmittals have the potential to result in recalculation of the WEC obligation for the WEC obligated party. As discussed in section III.A.4. of this preamble, the EPA proposes that data resubmissions for the previous reporting year would be required to be submitted by November 1 in order to be considered for WEC recalculations, with the exeption of resubmissions related to CAA section 111(b) or (d) compliance reports for the purposes of the regulatory compliance exemption. If the recalculated WEC obligation is less than the original WEC obligation owed by the WEC obligated party, we propose that the EPA would authorize a refund to the WEC obligated party equal to the difference in WEC obligation. If the recalculated WEC obligation is greater than the original WEC obligation owed by the WEC obligated party, the EPA would charge the WEC obligated party for the remaining balance of the WEC, including any assessed fees or penalties.[42] To encourage careful attention to detail and reduce the need for WEC filing revisions, we are proposing to charge a daily interest rate for any revised WEC filing that results in additional WEC being owed. As proposed in 40 CFR 99.8, this daily interest rate would be assessed from April 1st (*i.e.*, the day after the submission deadline) until such time that a resubmitted WEC filing and payment, that is subsequently verified by the EPA, is certified by the designated representative. We propose a daily interest rate equal to theCurrent Value of Funds Rate, consistent with 31 U.S.C. 3717(a). The EPA proposes that payment for any additional WEC, including assessed interest, would made with the resubmitted WEC filing.

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[42] We propose that WEC obligated parties would be subject to the financial sanctions proposed in 40 CFR 99.10 for any delinquent payments of the revised WEC invoice(s), as discussed in section III.B. of this preamble.

The EPA seeks comment on the proposed approach for resubmitted WEC filings, including the application of daily interest rate for revised WEC filings that result in additional WEC being owed.

2. Process for Assessing WEC for Unverified Part 99 Filings

As discussed in section III.A.4. of this preamble, the EPA's verification review process ideally ends with the resolution of identified potential errors through either correction and resubmission of facilities' reports or justification provided through correspondence with reporters that no substantive error exists. When WEC applicable facilities or WEC obligated parties do not provide appropriate information to resolve the errors in their part 98 or part 99 data after 45 days (with the possibility of a 30-day extension) of either being contacted in writing by the EPA notifying them of the presence of a substantive error or by self-discovering that a previously submitted part 98 report or WEC filing contains one or more substantive errors, the EPA considers their WEC filing to be unverified.

If a WEC filing is unverified but the EPA is able to correct the error(s) based on reported data, we propose that the EPA will recalculate the WEC using available information and provide an invoice or refund to the WEC Obligated Party within 60 days of determining a WEC filing to be unverified. If the WEC Obligated Party resubmits a WEC filing within that timeframe, the EPA would either accept the resubmission, or take the resubmission into account when calculating the WEC. In cases where the EPA is unable to calculate the WEC with available information, the WEC Obligated Party may be required to undergo a third-party audit. The third-party auditor must review records kept by the WEC Obligated Party, quantify the WEC with available information and in accordance with the requirements of this part, and submit the updated WEC calculations and supporting data to the EPA. The EPA would then take that information into consideration and calculate the WEC and provide an invoice to the WEC Obligated Party. Third-party audits may be required to be arranged by and conducted at the expense of the WEC obligated party.

A WEC obligated party would be required to pay an invoice received from the EPA for any updated WEC obligation by the specified due date, or within 30 days of the date of the invoice or bill if a due date is not provided.

The EPA requests comment on the proposed approach for assessing WEC for unverified part 99 reports, including the EPA recalculating WEC when data are available, and the option of requiring third-party auditing of WEC obligated party records when the EPA is not able to recalculate WEC with the available information. The EPA requests comment on an alternative approach that would establish default values (*e.g.*, industry segment-specific methane intensities) that would be conservative in nature and used to calculate WEC applicable emissions from unverified reports until such time that the report becomes verified. The calculated methane emissions from the unverified report(s) would then be included when determining the WEC obligated party's WEC obligation. In this approach, the EPA envisions that similar financial sanctions as those discussed in section III.B.2. of this preamble would be applied until a verified report is submitted and certified by the WEC applicable facility. We also seek comment on additional gap-filling approaches for unverified GHGRP reports. In addition, the EPA seeks comment on an approach for unverified reports that would apply daily penalties on unverified reports, up to the rate associated with U.S. Code citation 42 U.S.C. 7413(d)(1) specified in Table 1 of 40 CFR 19.4, as amended. Under such an approach, the EPA seeks comment on the duration of the penalty (*e.g.*, 3 years or until the report is verified, whichever is sooner).

C. Authorizing the Designated Representative

We are proposing provisions for each affected WEC obligated party to identify a designated representative. We are proposing that each WEC obligated party would each have one designated representative who is an individual selected by an agreement binding on the WEC obligated party. This designated representative would act as a legal representative between the WEC obligated party and the Agency. We are proposing that the designated representative must submit a complete certificate of representation at least 60 days prior to the submission of the first

WEC filing made by the WEC obligated party. Additionally, each WEC filing would contain a signed certification by a designated representative of the WEC obligated party. On behalf of the owner or operator, the designated representative would certify under penalty of law that the WEC filing has been prepared in accordance with the requirements of 40 CFR part 99 and that the information contained in the WEC filing is true and accurate, based on a reasonable inquiry of individuals responsible for obtaining the information.

We are also proposing that the designated representative could appoint an alternate to act on their behalf, but the designated representative would maintain legal responsibility for the submission of complete, true, and accurate emissions data and supplemental data. A designated representative or alternate designated representative may delegate one or more “agents.” The agent (*e.g.*, a part 98 subpart W designated representative who can provide facility-specific information) can enter data for a part 99 WEC filing, but is not allowed to submit, certify, or sign a WEC filing.

We are proposing that within 90 days after any change in the WEC obligated party, the designated representative or any alternate designated representative must submit a certificate of representation that is complete under this section to reflect the change.

D. General Recordkeeping Requirements

We are proposing that WEC applicable facilities and WEC obligated parties must retain all required records for at least 5 years from the date of submission of the WEC report for the reporting year in which the record was generated. We are proposing that the records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and auditing. Under the proposed provisions, upon request by the Administrator, the records required under this section must be made available to the EPA. We are proposing that records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, we are proposing that the equipment or software necessary to read the records shall be made available, or, if requested by the EPA, electronic records shall be converted to paper documents. The records that the EPA is proposing that must be retained would include information required to be retained under part 98, specifically subparts A and W, any other information needed to complete the WEC filing, and all information required to be submitted as part of the WEC filing, including any supporting documentation.

E. General Provisions, Including Auditing and Compliance and Enforcement

1. Auditing Provisions

We are proposing that the EPA may conduct on-site audits of facilities, as indicated in 40 CFR 99.7(c). Under the proposed general recordkeeping provision at 40 CFR 99.7(d), the records generated under this part would be available to the EPA during an on-site audit as the records must be recorded in a form that is suitable for expeditious inspection and review, and must be made available to the EPA upon request. The on-site audits may be conducted by private auditors contracted by the EPA or by Federal, State or local personnel, as appropriate, and may be required to be arranged by and conducted at the expense of the WEC obligated party.

2. Compliance and Enforcement

We are proposing that any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. 7414) and section 136 (*42 U.S.C. 7436*). A violation would include but is not limited to failure to submit, or resubmit as required, a WEC filing, failure to collect data needed to calculate the WEC charge (including any data relevant to determining the applicability of any exemptions), failure to retain records needed to verify the amount of WEC charge, providing false information in a WEC filing, and failure to remit WEC payment. As proposed at 40 CFR 99.4(b), it is a violation to fail to authorize a designated representative for a WEC obligated party. In the case of a facility with more than one owner or operator, failure to select a WEC obligated part would constitute a violation on the part of each owner or operator, as proposed at 40 CFR 99.4. Each day of a violation would constitute a separate violation.

IV. Proposed Confidentiality Determinations for Certain Data Reporting Elements

A. Overview and Background

In this action, the EPA is proposing to require WEC obligated parties to report the general information described in section III.A.3. of this preamble and the information specific to any applicable exemptions as described in sections II.D.1. through 3. of this preamble. This information is necessary for the EPA to verify the contents of the WEC filing, including confirming that all of the required WEC applicable facilities were included, each WEC applicable facility is eligible for any exemptions that were applied, and the WEC applicable emissions and the amount of the WEC obligation were calculated correctly. As explained in the remainder of this section, the EPA is proposing that nearly all of the data reported would be either emission data or otherwise ineligible for confidential treatment. The information that may be eligible for confidential treatment would be information included in supporting documentation required for eligible exemptions or additional information provided in software comments fields.

Section 114(c) of the CAA requires that "[a]ny records, reports, or information obtained under [CAA section 114(a)] shall be available to the public, except that upon a showing satisfactory to the Administrator by any person that records, reports, or information, or particular part thereof, (other than emission data) . . . if made public, would divulge methods or processes entitled to protection as trade secrets . . ., the Administrator shall consider such record, report, or information or particular portion thereof confidential. . . ." Thus, the CAA begins with a presumption that information submitted to the EPA may be disclosed to the public. It then provides a narrow exception to that presumption for information that "if made public, would divulge methods or processes entitled to protection as trade secrets. . . ." Section 114(c) of the CAA narrows this exception further by excluding "emission data" from the category of information eligible for confidential treatment. The EPA has interpreted CAA section 114(c) to afford confidential treatment to both trade secrets and confidential business information that are not emission data (40 FR 21987, 21990 (May 20, 1975)).

While the CAA does not define “emission data,” the EPA has done so by regulation at 40 CFR 2.301(a)(2)(i). Emission data means, with reference to any source of emissions of any substance into the air—

(A) Information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source (or of any pollutant resulting from any emission by the source), or any combination of the foregoing;

(B) Information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of the emissions which, under an applicable standard or limitation, the source was authorized to emit (including, to the extent necessary for such purposes, a description of the manner or rate of operation of the source); and

(C) A general description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources (including, to the extent necessary for such purposes, a description of the device, installation, or operation constituting the source).

Further, in a 1991 EPA notice of policy (56 FR 7042, February 21, 1991), the EPA stated that certain data fields constitute “emission data” and therefore cannot be withheld as confidential. The 1991 document indicated that while confidentiality determinations are typically made on a case-by-case basis, some kinds of data will always constitute emission data within the meaning of CAA section 114(c). The document listed several data fields that EPA considered to be emission data including facility identification data (*e.g.*, facility name; address; ownership; Standard Industrial Classification (SIC); emission point, device or operation description information) and emission parameters (*e.g.*, compounds emitted; origin of emissions; emission rate, concentration, release parameters, boiler or process design capacity, emission estimation method). The document clarified that the list of types of information in the document was not exhaustive and that other data might also constitute emission data.

For data that are not “emission data,” the confidentiality determination criteria at 40 CFR 2.208(a) through (d) are as follows:

Determinations issued under §§ 2.204 through 2.207 shall hold that business information is entitled to confidential treatment for the benefit of a particular business if:

(a) The business has asserted a business confidentiality claim which has not expired by its terms, nor been waived nor withdrawn;

(b) The business has satisfactorily shown that it has taken reasonable measures to protect the confidentiality of the information, and that it intends to continue to take such measures;

(c) The information is not, and has not been, reasonably obtainable without the business’s consent by other persons (other than governmental bodies) by use of legitimate means (other than discovery based on a showing of special need in a judicial or quasi-judicial proceeding); and

(d) No statute specifically requires disclosure of the information.

In *Food Marketing Institute* v. *Argus Leader Media*, 139 S. Ct. 2356 (2019) (hereafter referred to as *Argus Leader*), the U.S. Supreme Court issued an opinion addressing the meaning of the word “confidential” in Exemption 4 of the Freedom of Information Act, 5 U.S.C. Section 552(b)(4)(2012 and Supp. V. 2017) stating that “confidential” must be given its “ordinary” meaning, which is information that is “private” or “secret.” As a result, starting with the date of the *Argus Leader* ruling, the EPA no longer assesses data elements using the rationale of whether disclosure will cause a likelihood of substantial competitive harm when making confidentiality determinations. Instead, the EPA assesses whether the information is customarily and actually treated as private by the reporter and whether the EPA has given an assurance at the time the information was submitted that the information will be kept confidential or not confidential.

B. Proposed Confidentiality Determinations

Pursuant to CAA section 114(c), the EPA is proposing to make categorical emission data and confidentiality determinations in advance through this notice and comment rulemaking for the categories of information in these proposed reports under part 99. We describe the proposed emission data categories and confidentiality determinations for the reported information, as well as the basis for such proposed determinations, in this section. This approach is similar to the approach we have taken for the GHGRP under 40 CFR part 98 (see 75 FR 39094, July 7, 2010, and 75 FR 30782, May 26, 2011, for more information).

The determinations the EPA is proposing in this rulemaking, if finalized, would serve as notification of the Agency's decisions concerning: (1) the categories of information the Agency will not treat as confidential because it is emission data; (2) the information that is not emission data but is not entitled to confidential treatment; and (3) the information that the submitter may claim as confidential but will remain subject to the existing 40 CFR part 2 process. In responding to requests for information not determined in this proposal to be emission data or otherwise not entitled to confidential treatment, we propose to apply the default case-by-case process found in 40 CFR part 2.

The emission data and confidentiality determinations proposed in this rulemaking are intended to provide consistency in the treatment of the information collected by the EPA as part of the proposed WEC filings. The EPA anticipates that making these determinations in advance through this rulemaking will provide predictability and transparency for both information requesters and submitters.

The categories of information that we are proposing to determine to be emission data in this action are:

(1) Methane emissions;

(2) Calculation methodology; and

(3) Facility and unit identifier information.

The EPA is proposing to group types of information (data elements) that the Agency is proposing to require WEC obligated parties to submit under part 99 that would be considered emission data into these three categories based on their shared characteristics. For the sake of organization, for any information that logically could be grouped into more than one category, we have chosen to label information as being in just one category where we think it fits best. This approach will reduce redundancy within the categories that could lead to confusion and ensure consistency in the treatment of similar information in the future. We are requesting comment on the following: (1) our proposed categories of emission data; and (2) our placement of each data element under the category proposed.

For reporting elements that the EPA does not designate as "emission data," the EPA is proposing to assess each individual reporting element according to the *Argus Leader* criteria (*i.e.*, whether the information is customarily and actually treated as private by the submitter) and 40 CFR 2.208(a) through (d). Therefore, we are not proposing to establish categories and categorical confidentiality determinations for information that is not "emission data." However, we are proposing descriptions of the type of information that would not be eligible for confidential treatment in 40 CFR 99.13(b), including certain information demonstrating compliance with standards and information that is publicly available. We are also proposing in 40 CFR 99.13(c) through (e) to specify certain data elements and types of information that would be subject to the process for confidentiality determinations in 40 CFR part 2. The proposed provisions in 40 CFR 99.13(b) would establish the proposed confidentiality determinations of the proposed data elements in part 99 and would also provide clarity and ensure consistent treatment of new or substantively revised data elements if the content of the WEC filing is amended in a future rulemaking. Sections IV.B.2. and 3. of this preamble describe these proposed provisions, and our assessment of each individual reporting element that we are proposing is not "emission data." We are requesting comment on the proposed Agency determinations that information described in those sections of the preamble are not entitled to confidential treatment.

1. Emission Data

We are proposing to establish in 40 CFR 99.13(a) that certain categories of information the EPA would collect in the proposed WEC filings are information that meets the regulatory definition of emission data under 40 CFR 2.301(a)(2)(i). The following sections describe the categories of information we are proposing to determine to be emission data, based on application of the definition at 40 CFR 2.301(a)(2)(i) to the shared characteristics of the information in each category and our rationale for each proposed determination.

a. Information Necessary to Determine the Identity, Amount, Frequency, Concentration, or Other Characteristics of Emissions Emitted by the Source

Under 40 CFR 2.301(a)(2)(i)(A), emission data includes "[i]nformation necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source (or of any pollutant resulting from any emission by the source), or any combination of the foregoing[.]" We are proposing that the following categories of information are emission data under 40 CFR 2.301(a)(2)(i)(A):

(1) Methane emissions; and

(2) Calculation methodology.

Methane emissions. Data elements included in the Methane emissions data category are the net WEC emissions, facility waste emissions thresholds, industry segment waste emissions thresholds for each applicable industry segment within the facility (if more than one industry segment applies), and WEC applicable emissions, as well as the quantities of methane emissions that the WEC obligated party calculates should be exempted due to unreasonable delay and wells that were permanently shut-in and abandoned. The EPA proposes to determine that the emissions at each reporting level constitute "emission data." These data elements are information regarding the identity, amount, and frequency of any emission emitted by the WEC applicable facility, and, therefore, they are "emission data." As discussed in section IV.A. of this preamble, in the 1991

EPA notice of policy (56 FR 7042, February 21, 1991), the EPA identified, without attempting to be comprehensive, data elements that the EPA considered to constitute emission data. The 1991 document lists the "Emission type (*e.g.*, the nature of emissions, such as CO_2, particulate or a specific toxic compound, and origin of emissions such as process vents, storage tanks or equipment leaks)" and "Emission rate (*e.g.*, the amount released to the atmosphere over time such as kg/yr or lbs/yr)" as data that are not entitled to confidential treatment and are, therefore, releasable to the public. Our proposed determination for this data category is consistent with the 1991 document. It is also consistent with the determination for a similar category in the GHGRP under 40 CFR part 98.

Calculation methodology. The data element included in this category is the method used to determine the quantity of methane emissions that the WEC obligated party calculates should be exempt due to an unreasonable permitting delay and the method used to determine the equipment leaks emissions attributable to a plugged well. Most of the necessary calculations in part 99 do not include multiple equations or approaches that could be selected by a WEC obligated party, and in those cases, the calculation methodology used is readily apparent for any WEC obligated party. Calculations for the exemptions for unreasonable delay and plugged wells do include multiple equations that facilities may use under different circumstances.

The EPA proposes to determine that the data elements in the Calculation methodology category are "emission data" under 2.301(a)(2) because they are "information necessary to determine . . . the amount" of emissions emitted by the source. The method used to calculate emissions is emission data under 40 CFR 2.301(a)(2) because it is information necessary for the WEC obligated party to calculate the emissions and for the EPA and the public to verify that an appropriate method was used. As discussed in section IV.A. of this preamble, the 1991 EPA notice of policy provided a list of information that the EPA considered to constitute "emission data" under 40 CFR 2.301(a)(1)(2)(i). That list includes the "emission estimation method (*e.g.*, the method by which an emission estimate has been calculated such as material balance, source test, use of AP-42 emission factors, etc.)," which is the same type of data element as those that the EPA is proposing to include in this data category. Our proposed determination for this data category is consistent with the 1991 document. It is also consistent with the determination for a similar category in the GHGRP under 40 CFR part 98.

b. Information that is Emission Data Because it Provides a General Description of the Location and/or Nature of the Source to the Extent Necessary to Identify the Source and to Distinguish it from other Sources

Under 40 CFR 2.301(a)(2)(i)(C), emission data includes "a "[g]eneral description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources (including, to the extent necessary for such purposes, a description of the device, installation, or operation constituting the source)." We are proposing that the data elements in the Facility and unit identifier information category of information are emission data under 40 CFR 2.301(a)(2)(i)(C).

The proposed part 99 regulations would require WEC obligated parties to report in the WEC filing information needed to identify each facility as well as specific emission units (affected facilities) and/or well-pads associated with an exemption. Facility-identifying information must be reported for all facilities as specified in 40 CFR part 99, subpart A. Affected facility-specific identifying information is required for the regulatory compliance exemption. Well-pad-specific identifying information is reported if required by an applicable exemption for onshore petroleum and natural gas production facilities.

Data elements in this category would include the following data elements required under 40 CFR part 99, subpart A to be included in each annual WEC filing: WEC obligated party company name and address, the name and contact information for the designated representative of WEC obligated party, and a signed and dated certification statement of the accuracy and completeness of the report, which is provided by the designated representative of the owner or operator. The proposed part 99 regulations would also require that the filing include specific information about each facility covered by the annual WEC filing, including the e-GGRT ID number and the industry segment. For each exemption, the facility and unit identifier information category would include (as applicable) the facility identifier, the well-pad and/or well identifier reported under subpart W (if applicable), other facility or affected facility identifiers used to identify the facility/sources in other EPA systems (specifically, the ICIS-AIR ID or Facility Registry Service (FRS) ID and the EPA Registry ID from the Compliance and Emissions Data Reporting Interface (CEDRI)), emission source-specific methane mitigation activities impacted by an unreasonable permitting delay, and exemption-specific certification statements.

As discussed in section IV.A. of this preamble, emission data must be available to the public and is not entitled to confidential treatment under CAA section 114(c). "Emission data" is defined in 40 CFR 2.301(a)(2)(i)(C) to include "[a] general description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources . . . ." Consistent with this definition of emission data, the EPA considers facility and emission unit identifiers to be source information or "information necessary to determine the identity . . . of any emission which has been emitted by the source," and therefore emission data under 40 CFR 2.301(a)(2)(i). Further, 40 CFR 2.301(a)(2)(i)(A) specifies that emission data includes, among other things, "information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source. . . ." The EPA considers the term "identity . . . of any emission" as not simply referring only to the names of the pollutants being emitted, but to also include other identifying information, such as from what and where (*e.g.*, the identity of the emission unit) the pollutants are being emitted.

The 1991 EPA notice of policy (discussed in section IV.A. of this preamble) provided a list of data fields that the EPA considered to be emission data. For example, in the 1991 document, the EPA considered that plant name, address, city, State, zip code, emission point or device description, SIC code, and Source Classification Code (SCC) are emission data.

Therefore, the public has been on notice that the EPA considers many of the data elements in this data category to be emission data and thus not entitled to confidential treatment. The 1991 document also makes clear that the list of data is not comprehensive and that other data might also constitute emission data. This proposed part 99 determination that these data elements are emission data is consistent with the 1991 policy statement, and also consistent with the Facility and unit identifier information category in the GHGRP under 40 CFR part 98.

2. Reported Information that is Never Entitled to Confidential Treatment.

As noted in section IV.B. of this preamble, we are proposing to assess the confidentiality of each individual part 99 reporting element that is not otherwise designated as emission data in this rulemaking according to the *Argus Leader* criteria (*i.e.*, whether the information is customarily and actually treated as private by the submitter) and 40 CFR 2.208(a) through (d). However, in this action we are proposing descriptions of the type of information that would not be eligible for confidential treatment in 40 CFR 99.13(b), in part to establish the proposed confidentiality determinations of the proposed data elements in part 99 but also to provide clarity and consistency in the event that the content of the WEC filings are amended in a future rulemaking. The WEC obligation is calculated by multiplying the net WEC emissions by a set dollar amount, depending on the reporting year. As explained in section IV.B.1.a. of this preamble, the EPA is proposing to determine that the net WEC emissions are emission data. Therefore, we are proposing that the WEC obligation, which is calculated as the net WEC emissions multiplied by a dollar per ton rate that is prescribed in CAA section 136, would not be eligible for confidential treatment.

We are also proposing that certain information considered to be compliance information in part 99, regardless of whether it is or is not designated as emission data, is still not otherwise eligible for confidential treatment. Compliance information collected under part 99 includes information necessary to demonstrate compliance with the eligibility requirements for the exemptions for unreasonable permitting delay, regulatory compliance, and wells that have been permanently shut-in and plugged. Examples of the information collected include: for the unreasonable delay exemption, the date of the permit request, the estimated date to commence operation if the application had been approved within a set period of months, the first date that offtake to the gathering or transmission infrastructure from the implementation of methane emissions mitigation occurred once the application was approved, the beginning and ending date for which the eligible delay limited the offtake of natural gas associated with methane emissions mitigation activities, information on all applicable local, state, and Federal regulations regarding flaring emissions and the facility's compliance status for each, and other compliance information related to gathering or transmission infrastructure; for the regulatory compliance exemption, copies of reports and other evidence of compliance with NSPS OOOOb or a state, Tribal, or Federal plan under 40 CFR part 62; and for the plugged well exemption, the date a well was permanently shut-in and plugged and the statutory citation for the requirements that were followed for that process. Operating and construction permits are available to the public through the State issuing the permits (as the delegated authority of the EPA), generally either through an online information system or website, or upon request to the state agency issuing the permits. These permits are expected to contain information about the type and size of process equipment operated at a facility, control devices or other measures undertaken to reduce emissions from each process, and the emission standards to which the facility is subject (including Federal standards as well as state or local standards). Reports submitted by owners and operators of facilities subject to NSPS OOOOb or a state, Tribal, or Federal plan under 40 CFR part 62 are available through the EPA's online repository "WebFIRE." See *https://www.epa.gov/electronic-reporting-air-emissions/webfire*. Finally, well-specific information, including age, production rate, and operating status, is publicly available through state oil and gas commissions and/or state databases as well as sources such as Enverus. Because this information is already publicly available, it would not be eligible for confidential treatment.

The EPA is also proposing in 40 CFR 99.13(b)(3) that any other information that has been published and made publicly available, including the publicly available reports submitted under the GHGRP and information on websites, would not be eligible for confidential treatment. Information that is publicly available does not meet the criteria for information entitled to confidential treatment specified in 40 CFR 2.208(c). This proposed paragraph 40 CFR 99.13(b)(3) would specify an additional type of information that would not be eligible for confidential treatment when evaluating the confidentiality of supporting documentation submitted as described in proposed 40 CFR 99.13(c) or (d) (see section IV.B.3. for additional information on supporting documentation).

3. Information for Which the EPA is Not Proposing a Confidentiality Determination

This section describes information for which the EPA is not proposing a confidentiality determination. The EPA would initially treat this information as confidential upon receipt, if the submitter claimed it as such, until a case-by-case determination is made by the Agency under the 40 CFR part 2 process.

We do not expect emission data to be submitted in supporting documentation, but we are proposing that information in supporting documentation as described in proposed 40 CFR 99.13(c) (*i.e.*, information not listed in proposed 40 CFR 98.13(a) or (b) as not eligible for confidential treatment) would be treated as confidential until a case-by-case determination is made under the 40 CFR part 2 process. The EPA is also proposing that information provided in software comments fields as described in proposed 40 CFR 99.13(d) would not be eligible for confidential treatment if it is listed in proposed 40 CFR 98.13(a) or (b) as not eligible for confidential treatment. Otherwise, the EPA would treat the information as confidential until a case-by-case determination is made under the 40 CFR part 2 process, as specified in proposed 40 CFR 99.13(c). The EPA recognizes that supporting documentation and reporter comments may include information that is sensitive or proprietary, such as detailed process designs or site plans. Because the exact nature of this documentation cannot be predicted with certainty, the EPA proposes to make case-by-case confidentiality determinations under CAA section 114(c) for any supporting documentation or comments claimed confidential by applicants either upon receipt of such information or upon a request for such information after receipt.

C. Proposed Amendments to 40 CFR Part 2

As previously discussed, pursuant to CAA section 114(c), the EPA must make available to the public data submitted under part 99, except for data (other than emission data) that are considered confidential under CAA section 114(c). Accordingly, the EPA may release part 99 data without further notice after submission to the EPA in accordance with the EPA's determinations of their confidentiality status in the final rule. Specifically, the EPA may release part 99 data that are determined in the final rule to be emission data or not otherwise entitled to confidential treatment under CAA section 114(c) (*i.e.*, "non-CBI"). For data elements that we determine to be entitled to confidential treatment under CAA section 114(c), the EPA would release or publish such data only if the information can be aggregated in a manner that would protect the confidentiality of these data at the facility level. Existing regulations in 40 CFR part 2, subpart B set forth procedural steps that the EPA must follow before releasing any information, either on the Agency's own initiative or in response to requests made pursuant to FOIA. In particular, the EPA is generally required to make case-by-case confidentiality determinations and to notify individual reporters before disclosing information that businesses have submitted with a confidentiality claim. As discussed in section IV.B of this preamble, in light of the voluminous data the EPA receives under subpart W of part 98 and the multiple procedural steps required under 40 CFR part 2, subpart B, the EPA would not be able to make part 99 data (determined to be emission data or non-CBI) publicly available in a timely fashion if it were required to make separate confidentiality determinations based on each submitter's individual claim of confidentiality.

To facilitate timely release of GHG data collected under part 99 that are emission data or non-CBI, the EPA proposes to amend 40 CFR 2.301, Special rules governing certain information obtained under the Clean Air Act. Specifically, the EPA is proposing to revise 40 CFR 2.301(d) to specify that the special rules for data submitted under part 98 would also apply to part 99. Under the proposed amendment, the EPA may release part 99 data that are determined to be emission data or information determined to be not entitled to confidential treatment upon finalizing the confidentiality status of these data. Consistent with the 40 CFR part 2 procedures, the approach proposed in this rulemaking would provide the WEC obligated party an opportunity to justify and substantiate any confidentiality claim they may have for the data they are required to submit (except for emission data and other data not entitled to confidential treatment pursuant to CAA section 114(c)). In addition, WEC obligated parties have the benefit of seeing the EPA's rationales and analyses prior to submitting any justification, information that they would not otherwise have under the current 40 CFR part 2 procedures. As more fully explained in section IV.E of this preamble, the WEC obligated party must provide comment explaining why it disagrees with the rationale provided by the EPA for each particular data element it intends to claim confidential and must provide information to explain how the business customarily and actually treats the information as confidential. The EPA will consider comments received on this proposal before finalizing the confidentiality determinations.

The EPA solicits comment on the proposed amendments to 40 CFR 2.301(d), Special rules governing certain information obtained under the CAA for data submitted under part 99.

D. Proposed Changes to Confidentiality Determinations for Data Elements Reported Under Subpart W

The industry segment waste emissions thresholds are calculated pursuant to 40 CFR 99.20. Except for facilities in the Offshore Petroleum and Natural Gas Production industry segment or the Onshore Petroleum and Natural Gas Production industry segment that have no natural gas sent to sale, each threshold is calculated by multiplying the specified natural gas throughput for that industry segment by two constant values, the density of methane and the industry segment-specific methane intensity threshold (as summarized in Table 2 of this preamble). As noted in section IV.B.1.a. of this preamble, the EPA is proposing that the facility waste emissions thresholds and industry segment waste emissions thresholds are emission data and would therefore be made publicly available. For two industry segments, Onshore Natural Gas Processing and Onshore Natural Gas Transmission Compression, throughput quantities similar to those specified in the industry segment waste emissions threshold calculations have historically not been made publicly available under subpart W. However, for WEC applicable facilities, once the industry segment-specific waste emissions thresholds are made publicly available, the throughputs can be calculated based on available information.

Therefore, the EPA is proposing to address confidentiality determinations for two subpart W data elements as part of this rulemaking. For the Onshore Natural Gas Processing industry segment, a new data element was proposed as part of 2023 Subpart W Proposal, the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year, in thousand standard cubic feet, reported under proposed § 98.236(aa)(3)(ix). The EPA made a final determination in 79 FR 70352 (November 25, 2014) that the quantity of natural gas received at the gas processing plant in the calendar year (reported under 40 CFR 98.236(aa)(3)(i)) and the quantity of processed (residue) gas leaving the gas processing plant (reported under 40 CFR 98.236(aa)(3)(ii)), should be maintained as confidential. As explained in 79 FR 70352 (November 25, 2014), the reporting of this information to the Energy Information Administration is less frequent than required under subpart W, and the EPA had not identified any reliable public sources of the quantity of residue gas produced. In the June 2023 memorandum *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems* (Docket ID No. EPA-HQ-OAR-2023-0234-0167), the EPA stated that the proposed new data element under 40 CFR 98.236(aa)(3)(ix) would collect similar information to 40 CFR 98.236(aa)(3)(ii). As a result, the EPA proposed to determine that the information collected under 40 CFR 98.236(aa)(3)(ix) would be eligible for confidential treatment.

However, if the EPA finalizes the proposed determination that the industry segment-specific waste emissions thresholds are emission data, then those industry segment-specific waste emissions thresholds would be made publicly available as emission data. Therefore, the EPA is no longer proposing a confidentiality determination for this throughput quantity data element (*i.e.*, the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year) under part 98. The confidentiality status of this data element would be evaluated on a case-by-case basis, in light of any publicly available information and in accordance with the existing regulations in 40 CFR part 2, subpart B, upon receipt of a public request for these data elements.

For Onshore Natural Gas Transmission Compression, the EPA previously decided in 2014 not to make a confidentiality determination that would apply for all facilities for 40 CFR 98.236(aa)(4)(i), the quantity of gas transported through a compressor station. In 79 FR 70352 (November 25, 2014), the EPA explained that we proposed that this data element would not be eligible for confidential treatment because natural gas transmission sector is heavily regulated by FERC and state commissions, resulting in a lack of competition between companies. However, we received comments from this industry sector noting that FERC Order 636 had introduced greater competition to this sector and that some companies charge customers less than the FERC approved rates because of competitive market pressures. The commenters indicated that quantity of gas transported through the compressor station would provide information on the quantity of gas transported by a specific pipeline, which may potentially cause competitive harm to some pipeline companies operating in more competitive market areas. Since the determination would depend on the particular market conditions for each company, the EPA did not make a determination for the data element that would apply for all reporters.[43]

In this rulemaking, the EPA is not proposing to change that previous decision and is still not proposing a confidentiality determination for the quantity of natural gas transported through a compressor station. While the Supreme Court's 2019 decision in *Argus Leader* altered the review criteria for confidentiality determinations from the Agency's 2014 decision, the basis provided by commenters to justify the confidential nature of the information is still relevant. For information pertaining to the quantity of gas transported through a compressor station collected under part 99, the EPA will conduct reviews of any claims made under the existing regulations in 40 CFR part 2, subpart B, upon receipt of a public request for this information. Any such reviews will consider the public availability of the same or similar information, including WEC filings, as part of the determination process.

E. Request for Comments on Proposed Category Assignments, Confidentiality Determinations, or Reporting Determinations

This rulemaking provides affected entities that would be subject to part 99, other stakeholders, and the general public an opportunity to provide comment on the proposed amendment to 40 CFR 2.301(d) and the proposed confidentiality determinations for part 99 data, including our proposed categories of emission data and the proposed confidentiality determinations for each data element that is not considered emission data. By proposing emission data and confidentiality determinations prior to data reporting through this proposal and rulemaking process, we are providing potentially affected entities an opportunity to submit comments, particularly comments addressing any data elements not entitled to confidential treatment under this proposal, but which companies customarily and actually treat as private. This opportunity to submit comments is intended to provide reporters with the opportunity to

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[43] Prior to *Argus Leader*, the EPA considered whether the business had satisfactorily shown that disclosure of the information is likely to cause substantial harm to the business's competitive position when evaluating claims of confidentiality.

substantiate their confidentiality claims that would ordinarily be afforded when the EPA considers claims for confidential treatment of information in case-by-case confidentiality determinations under 40 CFR part 2. In addition, the comment period provides an opportunity to respond to the EPA's proposed determinations with more information for the Agency to consider prior to finalization. We will evaluate the comments on our proposed determinations, including claims of confidentiality and information substantiating such claims, before finalizing the confidentiality determinations. Please note that this will be reporters' only opportunity to substantiate a confidentiality claim for data elements included in this proposed rule where information being reported is proposed to be not entitled to confidential treatment. Upon finalizing the confidentiality determinations and reporting determinations of the data elements identified in this proposed rule, the EPA plans to release or withhold these data without further notice in accordance with proposed 40 CFR 2.301(d), which contains special provisions governing the treatment of part 99 data for which confidentiality determinations have been made through rulemaking pursuant to CAA sections 114, 136, and 307(d).

When submitting comments regarding the confidentiality determinations we are proposing in this action, please identify each individual proposed data element on which you are commenting and whether you consider the element to be confidential or do not consider to be "emission data" in your comments. If the data element has been designated as "emission data," please explain why you do not believe the information meets the definition of "emission data" as defined in 40 CFR 2.301(a)(2)(i). If the data has not been designated as "emission data" and is proposed to not be entitled to confidential treatment, please explain specifically how the data element is commercial or financial information that is both customarily and actually treated as private. Particularly describe the measures currently taken to keep the data confidential and how that information has been customarily treated by your company and/or business sector in the past. This explanation is based on the requirements for confidential treatment set forth in *Argus Leader*.

Members of the public may also discuss how this data element may be different from or similar to data that are already publicly available, including data already collected and published annually by the GHGRP, as applicable. Please submit information identifying any publicly available sources of information containing the specific data elements in question. Data that are already available through other sources would likely be found not to qualify for confidential treatment. In your comments, please identify the manner and location in which each specific data element you identify is publicly available, including a citation. If the data are physically published, such as in a book, industry trade publication, or Federal agency publication, provide the title, volume number (if applicable), author(s), publisher, publication date, and International Standard Book Number (ISBN) or other identifier. For data published on a website, provide the address of the website, the date you last visited the website and identify the website publisher and content author. Please avoid conclusory and unsubstantiated statements, or general assertions regarding the confidential nature of the information.

In addition to soliciting comment on our proposed confidentiality designations and proposed amendments to 40 CFR 2.301, we are also soliciting comment on the following specific issues relevant to the proposed confidentiality determinations:

"Emission Data" determination. As previously discussed, "emission data" cannot be kept confidential per CAA section 114. The EPA is seeking comment on the part 99 data elements proposed to be considered "emission data." Please specify exactly what part 99 data you think should be considered emission data, describe what part 99 data you think should not be emission data and why (and whether such non-emission data should be considered confidential and why), and clearly explain how the suggested definition of "emission data" would be consistent with the "necessary to determine" clause in 40 CFR 2.301, as well as with the purpose behind the statutory language.

Individual determinations. The EPA is proposing confidentiality determinations by data element for the majority of the data elements in part 99. We are soliciting comment on whether there are data elements proposed to be included in 40 CFR 99.13(a) and (b) for which we should not finalize a confidentiality determination for the data element as not eligible for confidential treatment and instead make no determination for the data element, such that the confidentiality status of this data element would be evaluated on a case-by-case basis, in light of any publicly available information and in accordance with the existing CBI regulations in 40 CFR part 2, subpart B, upon receipt of a public request for these data elements. If respondents believe that EPA should not make a determination for a specific data element, please describe specifics of when a case-by-case determination would be necessary.

Changes to determinations for subpart W throughputs. We request comment on the approach for the subpart W data elements specified in section IV.D. of this preamble. In particular, we request comment on no longer proposing a confidentiality determination for the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year, in thousand standard cubic feet, reported under proposed 40 CFR 98.236(aa)(3)(ix). We also request comment on the proposal to continue not making a confidentiality determination for the quantity of natural gas transported through a compressor station under 40 CFR 98.236(aa)(4)(i), as well as the criteria that should be used to conduct a case-by-case evaluation of the confidentiality of the data. We also request comment on whether these two data elements are customarily and actually treated as confidential, and if so, what approaches the EPA could use to treat the information as confidential while still making all emission data publicly available, as required by CAA section 114(c).

V. Impacts of the Proposed Amendments

In accordance with the requirements of Executive Order 12866, the EPA projected the emissions reductions, costs, benefits, and transfer payments that may result from this proposed action if finalized as proposed. These results are presented in detail in the *Regulatory Impact Analysis of the Proposed Waste Emission Charge* (RIA) accompanying this proposal developed in response to Executive Order 12866 and available in the docket to this rulemaking, Docket ID No. EPA-HQ-OAR-2023-0434. This section provides a brief summary of the RIA.

The WEC does not directly require emissions reductions from applicable facilities or emissions sources. However, by imposing a charge on methane emissions that exceed waste emissions thresholds, oil and natural gas facilities subject to the WEC are expected to perform methane mitigation actions and make operational changes where the costs of those changes are less than the WEC payments that could be avoided by reducing methane emissions. In addition, because VOC and HAP emissions are emitted along with methane from oil and natural gas industry activities, reductions in methane emissions as a result of the WEC also result in co-reductions of VOC and HAP emissions.

The RIA accompanying this proposal analyzes emissions changes and economic impacts of the WEC that arise through two pathways: 1) through the application of cost-effective methane mitigation technologies, and 2) through changes in oil and natural gas production and prices resulting from the WEC and associated mitigation responses. The analysis of methane mitigation is based on bottom-up engineering cost and mitigation potential information for a range of methane mitigation technologies. Application of methane mitigation technologies reduce WEC payments for WEC obligated parties by reducing methane emissions compared to a baseline without additional methane mitigation actions. The analysis assumes that methane mitigation is implemented where the engineering control costs are less than the avoided WEC payments for a particular mitigation technology.

Additionally, oil and natural gas firms may change their production and operational decisions in response to the WEC. This potential impact is modeled using a partial equilibrium model of the crude oil and natural gas markets. The total cost of methane mitigation and WEC payments is added as an increase to production costs, resulting in changes in equilibrium production of oil and natural gas and associated emissions. Projected WEC payments are estimated after methane emissions reductions from both methane mitigation and economic impacts are accounted for.

Using emissions reported to subpart W for RY2021 as an illustrative example, Table 1-1 of the RIA shows that the WEC would be imposed on less than 15 percent of national methane emissions from petroleum and natural gas systems. Total methane emissions reported to subpart W are significantly less than national methane emissions from the U.S. Greenhouse Gas Inventory. WEC-applicable facilities are the subset of GHGRP facilities that report at least 25,000 mt CO_2e to subpart W industry segments subject to the WEC. It is also important to note that the WEC would only apply to methane emissions that are above the emissions threshold, not for all emissions from WEC-applicable facilities. The WEC has exemptions related to regulatory compliance, emissions from plugged wells, and unreasonable delay in environmental permitting, although these provisions do not impact the illustrative results in Table 1-1 of the RIA. Finally, emissions subject to WEC accounts for netting of emissions between facilities. Under the proposed WEC, facilities with emissions below their emissions threshold may reduce emissions subject to the WEC at other facilities with emissions above the emissions threshold where those facilities are under common ownership or control.

The benefit-cost analysis contained in the RIA accompanying this rulemaking for the WEC considers the potential benefits and costs of the WEC arising from cost-effective mitigation actions under the WEC as well as the potential transfers from affected operators to the government in payments. Costs include engineering costs for methane mitigation actions and costs resulting from production changes in oil and gas energy markets under this rule. While the EPA expects a range of health and environmental benefits from reductions in methane, VOC, and HAP emissions under the WEC, the monetized benefits of the rule are limited to the estimated climate benefits from projected methane emissions reductions. These benefits are based on the social cost of greenhouse gases (SC-GHG). A screening-level analysis of ozone-related benefits from projected VOC reductions can be found in Appendix A of the RIA.

However, these estimates are treated as illustrative and are not included in the quantified benefit-cost comparisons in the RIA.

The EPA estimates that this action will result in cumulative emissions reductions of 960 thousand metric tons of methane over the 2024 to 2035 period. These reductions represent about 33 percent of methane emissions that would be subject to the WEC before accounting for the adoption of cost-effective emission reduction technologies. Virtually all the reduced emissions result from mitigation activities undertaken by industry to reduce WEC payments. Less than one percent of reductions are associated with decreased production activity in the oil and gas sector resulting from the proposed rule. In addition to methane emissions reductions, the WEC is estimated to result in reductions of 140 thousand metric tons of VOC and five thousand metric tons of HAP.

The WEC has important interactions and is designed to work hand-in-hand with the NSPS and EG for the Oil and Natural Gas Sector by accelerating the adoption of cost-effective methane mitigation technologies, including those that would eventually be required under the NSPS or EG. The annual projected emissions reductions, costs, and WEC obligations are significantly affected by these interactions.

The EPA proposed updates to the Oil and Gas NSPS OOOOb/EG OOOOc in 2021, published a supplemental proposal in 2022, and finalized in December 2023. In addition to requirements already in place, these rules include standards for many of the major sources of methane emissions in the oil and natural gas industry. To avoid double counting of benefits and costs, the baseline for this proposal includes reductions resulting from the NSPS OOOOb/EG OOOOc based on information from the 2023 Final RIA. Specifically, that analysis showed deep reductions in methane emissions beginning to take effect in 2028. As facilities implement emission controls required by the NSPS and EG, emissions subject to the WEC decline.

The second interaction between the WEC and NSPS OOOOb/EG OOOOc is the regulatory compliance exemption provision of the WEC. Under this provision, when certain conditions are met with respect to the implementation of the Oil and Gas NSPS OOOOb/EG OOOOc, applicable facilities in compliance with their applicable methane emissions requirements are exempted from the WEC. The analysis in the RIA assumes that the regulatory compliance exemption takes effect in 2027, such that in 2027 and later, facilities in the industry segments subject to requirements under the NSPS OOOOb/EG OOOOc do not owe WEC payments.

Climate benefits associated with this proposed rule are the monetized value of GHG reductions using the SC-GHG, which calculates the avoided climate related damages from reducing GHG emissions. Methane is the principal component of natural gas. As discussed in section I.C.1. of this preamble, methane is also a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change.

This proposed rulemaking is projected to reduce VOC emissions, which are a precursor to ozone. Ozone is not generally emitted directly into the atmosphere but is created when its two primary precursors, VOC and oxides of nitrogen (NO_X), react in the atmosphere in the presence of sunlight. Emissions reductions under the WEC may decrease ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. VOC emissions are also a precursor to $PM_{2.5}$, so VOC reductions may also decrease human exposure to $PM_{2.5}$ and the incidence of $PM_{2.5}$- related health effects.

Available emissions data show that several different HAP are emitted from oil and natural gas operations. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and natural gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4- trimethylpentane.[44] Reductions of HAP emissions under the WEC may reduce exposure to these and other HAP.

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[44] U.S. EPA. The Benefits and Costs of the Clean Air Act from 1990 to 2020. Washington, DC. Retrieved from *https://www.epa.gov/sites/production/files/2015-07/documents/fullreport_rev_a.pdf*.

In section 9.3 of the RIA, the EPA identifies existing potential environmental justice issues for the communities in counties that have emissions sources that are expected to owe the WEC charge before accounting for mitigation actions and thus may be positively affected by emissions changes under the proposal. Compared to the national average, these communities include a higher percentage of individuals who identify as racial and ethnic minorities, have lower average incomes, and have slightly elevated health risks associated with various air emissions. Reductions in VOC and HAP emissions as a result of the WEC are expected to benefit communities in these counties. Because the WEC does not directly require emissions reductions, the EPA has not projected specific locations where emissions reductions might occur. In addition, detailed proximity analysis is infeasible because the emissions affected by the WEC occur at hundreds of thousands of locations.

The total cost of the proposed rule includes the engineering costs for methane mitigation actions implemented by the oil and natural gas industry in order to avoid or reduce WEC obligations. This includes the initial capital costs required to implement and install the specific mitigation technology. In addition, for mitigation technologies with expected lifetimes greater than one-year, annual recurring operations and maintenance costs, which include labor, energy and materials, are also incorporated. Finally, the total mitigation costs also include the avoided cost of natural gas losses.

The social cost of energy market impacts is the loss in consumer and producer surplus value from changes in natural gas market production and prices. The economic impacts analysis uses a partial equilibrium model and estimates that the impact of the gas market is minimal, with the largest impact occurring in the first few years with a price increase of less than 0.1 percent and a quantity reduction of less than 0.1 percent.

Table 5 presents results of the benefit-cost analysis for the proposed WEC. It presents the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 2, 3, and 7 percent, of the changes in quantified benefits, costs, and net benefits relative to the baseline.[45] These values reflect an analytical time horizon of 2024 to 2035, are discounted to 2023, and are presented in 2019 constant dollars. The table includes consideration of the non-monetized benefits associated with the emissions reductions projected under this proposal.

Table 4. Projected Emissions Reductions Under the Proposed Rule, 2024-2035 Total

Pollutant	Emissions Reductions (2024-2035 Total)
Methane (thousand metric tons)[a]	960
VOC (thousand metric tons)	140
Hazardous Air Pollutant (thousand short tons)	5
Methane (million metric tons CO_2e)[b]	27

[a] To convert from metric tons to short tons, multiply the short tons by 1.102. Alternatively, to convert from short tons to metric tons, multiply the short tons by 0.907.

[b] Carbon dioxide equivalent (CO_2e). Calculated using a global warming potential of 28.

Table 5. Benefits, Costs, and Net Benefits of the Proposed Rule, 2024 Through 2035 (dollar estimates in millions of 2019 dollars) [a]

	2 Percent Near-Term Ramsey Discount Rate					
	Present Value	Equivalent Annual Value	Present Value	Equivalent Annual Value	Present Value	Equivalent Annual Value
Climate Benefits[b]	$1,900	$180	$1,900	$180	$1,900	$180
	2 Percent Discount Rate		3 Percent Discount Rate		7 Percent Discount Rate	

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[45] Monetized climate effects are presented under a 2 percent near-term Ramsey discount rate, consistent with EPA's updated estimates of the SC-GHG. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. OMB finalized an update to Circular A-4 in 2023, in which it recommended the general application of a 2.0 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. Because the SC-GHG estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the discount rate estimated using the average return on capital (7 percent in OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG. See section 6.1 of the RIA for more discussion.

	Present Value	**Equivalent Annual Value**	**Present Value**	**Equivalent Annual Value**	**Present Value**	**Equivalent Annual Value**
Total Social Costs	$390	$37	$380	$38	$340	$43
Cost of Methane Mitigation	$360	$34	$350	$35	$320	$40
Cost of Energy Market Impacts	$30	$3	$29	$3	$26	$3
Net Benefits	$1,500	$140	$1,500	$140	$1,600	$140
Non-Monetized Benefits	Climate and ozone health benefits from reducing 960 thousand metric tons of methane from 2024 to 2035					
	$PM_{2.5}$ and ozone health benefits from reducing 140 thousand metric tons of VOC from 2024 to 2035[c]					
	HAP benefits from reducing 5 thousand metric tons of HAP from 2024 to 2035					
	Visibility benefits					
	Reduced vegetation effects					

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

[b] Climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Table 6-5 of the RIA for the full range of monetized climate benefits estimates.

[c] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix A of the RIA.

WEC payments are transfers and do not affect total net benefits to society as a whole because payments by oil and natural gas operators are offset by receipts by the government. Therefore, from a net-benefit accounting perspective, transfers are considered separately from costs and benefits (and are therefore not included in Table 5). As explained further in section 2.7 of the RIA, the approach taken here is in line with OMB guidance and the approach taken for RIAs for other rules impacting payments to the government, such as the Bureau of Land Management (BLM)'s waste prevention rule.

One of the reasons that transfers are not considered costs is because they represent payments to the U.S. Treasury that do not affect total resources available to society. Payments to the U.S. Treasury can then be used to fund other programs, and the pairing of revenue collection (e.g., the WEC payments) with commensurate expenditures (e.g., financial assistance programs) by the federal government can be designed to be revenue neutral. The Methane Emission Reduction Program created under CAA section 136 includes both collection and expenditure components. In addition to establishing the WEC, another key purpose of CAA section 136 is to encourage the development of innovative technologies in the detection and mitigation of methane emissions. See 168 Cong. Rec. E869 (August 23, 2022) (statement of Rep. Frank Pallone). CAA section 136(a) and (b) provides $1.55 billion to, among other things, help finance the early adoption of emissions reduction methodologies and technologies and to support monitoring of methane emissions. These incentives for methane mitigation and monitoring complement the WEC.

The WEC has the effect of better aligning the economic incentives of oil and natural gas companies with the costs and benefits faced by society from oil and gas activities. In the baseline scenario the environmental damages resulting from methane emissions from the oil and gas sector are a negative externality spread across society as a whole. Under the WEC, this negative externality is internalized, oil and gas companies are required to make WEC payments in proportion to the climate damages of methane emissions subject to the WEC. Alternatively, firms can avoid making WEC payments by mitigating their emissions generating climate benefits associated with the amount of mitigation.

Table 6 provides details of the calculation steps used to estimate projected WEC obligations and climate damages based on projected emission subject to WEC. In order to compare projected WEC payments to climate damages from emissions subject to the WEC, WEC payments are converted from nominal dollars to 2019 constant dollars using a chain-weighted GDP price index from the 2023 Annual Energy Outlook. Projected WEC payments after accounting for methane mitigation and energy market impacts are estimated to be about $750 million nominal dollars in 2024, and then drop significantly as the regulatory compliance exemption takes effect in 2027.

Table 6. Benefits, Costs, and Net Benefits of the Proposed Rule, 2024 Through 2035 (dollar estimates in millions of 2019 dollars) [a]

Year	Methane Emissions Subject to WEC in Policy Scenario (thousand metric tons)	Charge Specified by Congress (nominal $ per metric ton)	WEC Payments in Policy Scenario (million nominal $)	WEC Payments in Policy Scenario (million 2019$)	$SC\text{-}CH_4$ Values at 2% Discount Rate (2019$ per metric ton)	Climate Damages from Emissions Subject to WEC (million 2019$)[a]
2024	830	$900	$750	$620	$1,900	$1,600
2025	650	$1,200	$770	$630	$2,000	$1,300
2026	430	$1,500	$640	$510	$2,100	$890
2027	9	$1,500	$13	$10	$2,200	$18
2028	9	$1,500	$13	$10	$2,200	$19
2029	9	$1,500	$13	$10	$2,300	$20
2030	9	$1,500	$13	$9	$2,400	$20
2031	9	$1,500	$13	$9	$2,500	$21
2032	9	$1,500	$13	$9	$2,500	$21
2033	8	$1,500	$13	$9	$2,600	$21
2034	8	$1,500	$13	$8	$2,700	$21
2035	8	$1,500	$13	$8	$2,800	$21
Total 2024-2035	2,000	-	$2,300	$1,800	-	$4,000

[a] Climate damages are based on remaining methane emissions subject to WEC after accounting for emissions reductions and are calculated using three different estimates of the social cost of methane ($SC\text{-}CH_4$) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the $SC\text{-}CH_4$ at the 2 percent near-term Ramsey discount rate.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a "significant regulatory action" as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket for this rulemaking, Docket ID No. EPA-HQ-OAR-2023-0434. The EPA prepared an analysis of the potential impacts associated with this action. This analysis**,** *Regulatory Impact Analysis of the Proposed Waste Emission Charge***,** is also available in the docket to this rulemaking and is briefly summarized in section V. of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2787.01. You can find a copy of the ICR in the docket for this rule, Docket ID No. EPA-HQ-OAR-2023-0434, and it is briefly summarized here.

The EPA estimates that the proposed rule would result in an increase in burden. The burden associated with the proposed rule is due to reporting and recordkeeping requirements in the proposed rule.

The respondent reporting burden for this collection of information is estimated to be an annual average of 12,799 hours and $1,700,304 over the 3 years covered by this information collection, which includes an annual average of $1,669,752 in labor costs, $0 in operation and maintenance costs, and $30,552 in capital costs. The annual average incremental burden to the EPA for this period is anticipated at 31,200 hours and $5,670,955 ($2023) over the 3 years covered by this information collection, which includes an annual average of $2,004,288 in labor costs and $3,666,667 in non-labor costs.

Respondents/affected entities: Owners and operators of petroleum and natural gas systems that must submit a WEC filing to the EPA to comply with proposed 40 CFR part 99.

Respondent's obligation to respond: The respondent's obligation to respond is mandatory under the authority provided in CAA sections 114 and 136.

Estimated number of respondents: 536.

Frequency of response: Annually.

Total estimated burden: 12,799 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1.7 million (per year), includes $30,552 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *https://www.reginfo.gov/public/do/PRAMain*. Find this particular information collection by selecting "Currently under Review – Open for Public Comments" or by using the search function. OMB must receive comments no later than **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this proposed action would not have a significant economic impact on a substantial number of small entities under the RFA. The small entities that would be subject to the proposed requirements of this action are small businesses in the petroleum and natural gas industry. Small entities include small businesses, small organizations, and small governmental jurisdictions. The EPA has determined that some small entities are affected because their processes emit methane that must be reported under subpart W and thus may be subject to WEC.

To evaluate whether this proposed rule would have a significant economic impact on a substantial number of small entities, the EPA conducted a small entity analysis that evaluated the costs of the proposed rule on small entities identified in the reporting year (RY) 2021 subpart W dataset. The EPA used reported facility-to-parent company and facility-to-owner or operator data to link facilities to WEC obligated parties. The EPA then reviewed the available RY 2021 data for the WEC obligated parties of subpart W facilities to determine whether the reporters were part of a small entity and whether the annualized costs of the proposal would have a significant impact on a substantial number of small entities. The number of small entities potentially affected by the proposed WEC regulation were estimated based on the information collected for 472 WEC obligated parties. Of these, 439 were identified as small entities. Although the screening analysis suggests that some small entities may have cost-to-revenue ratios that exceed 3 percent (approximately 17 percent), the EPA’s evaluation of the impacts to small entities relied on several methodologies involving conservative assumptions. For example, the identification and classification of subpart W parent entities reporting under more than one NAICS code resulted in a designation of “small” based on whether the business information available met the SBA size classification threshold for a single NAICS code. In addition to the conservative assumptions, there were further mitigating factors not included in the screening analysis that would likely significantly reduce compliance costs, and, as a result, cost-to-revenue-ratios. For example, the compliance cost estimate used only the defined WEC cost and did not account for early adoption of mitigation measures that could lower an entity's emissions below the threshold and therefore result in no WEC charge. Details of this analysis are presented in the *Regulatory Impact Analysis of the Proposed Waste Emissions Charge*, available in the docket for this rulemaking. The cumulative effect of the mitigating factors and conservative assumptions used in the screening analysis indicates that, overall, the proposed rule would not likely have a significant impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action contains a federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA has prepared under section 202 of the UMRA a written statement of the benefit-cost analysis, which can be found in Section V of this preamble and in the *Regulatory Impact Analysis of the Proposed Waste Emissions Charge* (RIA), available in the docket for this rulemaking. The proposed action in part implements mandate(s) specifically and explicitly set forth in CAA section 136.

The applicability, magnitude of charge, methane emissions subject to charge, and exemptions from charge for the WEC program are established by CAA section 136(c) through (g). Given that this framework is required by statute, it is not possible for EPA to consider regulatory alternatives that are inconsistent with these elements. As such, to evaluate the benefits and costs of the proposed rule, in the RIA accompanying this rulemaking two scenarios were evaluated: a baseline scenario (*i.e.,* not including the effects of the WEC program) and a policy scenario inclusive of the costs, benefits, and transfers projected under the proposed rule. This action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This proposed rule does not apply to governmental entities unless the government entity owns a facility in the applicable petroleum and gas industry segments and reports more 25,000 mt CO_2e to subpart W of the GHGRP. It would not impose any implementation responsibilities on state, local, or tribal governments and it is not expected to increase the cost of existing regulatory programs managed by those governments. Thus, the impact on governments affected by the proposed rule is expected to be minimal.

However, consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA sought comments from small governments concerning the regulatory requirements that might significantly or uniquely affect them in the development of this proposed rule. Specifically, the EPA previously published a Request for Information (RFI) seeking public comment in a non-regulatory docket to collect responses to a range of questions related to the Methane Emissions Reduction Program, including related to implementation of the WEC (see Docket ID No. EPA-HQ-OAR-2022-0875). The EPA received five comments from government entities related to implementation of the WEC; these comments were considered during the development of the proposed rule. The EPA continues to be interested in the potential impacts of the proposed rule amendments on state, local, or tribal governments and welcomes comments on issues related to such impacts.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. This proposed rule will not apply to governmental entities unless the government entity owns a facility in the applicable petroleum and gas industry segments that and reports more 25,000 mt CO_2e to subpart W of the GHGRP. Therefore, the EPA anticipates relatively few state or local government facilities will be affected. However, consistent with the EPA's policy to promote communications between EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This proposed regulation will apply directly to petroleum and natural gas facilities that may be owned by tribal governments. However, it will generally only have tribal implications where the tribal entity owns a facility in an applicable industry segment that emits GHGs above threshold levels; therefore, relatively few tribal facilities will be affected. Of the subpart W facilities currently reporting to the GHGRP in RY2021, we identified four facilities currently reporting to part 98, subpart W that are owned or partially owned by one tribal parent company. Based on RY2021 data, all four facilities would be WEC applicable facilities, and the WEC applicable emissions (without consideration of exemptions) for the individual facilities would range from less than 0 mt CH_4 for one facility, up to about 3,500 mt CH_4 for the largest facility (which corresponds to a WEC obligation of $3.1 million). Note that one of the facilities is within the onshore natural gas processing sector, and thus, this calculation utilizes proxy data of CBI throughput, which may not reflect the actual facility throughput and resulting WEC applicable emissions. Each of the four facilities has a different owner or operator or combination of owners or operators, so the tribe likely would not be the WEC obligated party for all four facilities. These estimates do not consider any exemptions that might apply for the three facilities with emissions greater than the facility waste emissions threshold.

In addition to tribes that would be directly impacted by the WEC due to owning a facility subject to the charge, the EPA anticipates that tribes could be impacted in cases where facilities subject to the charge are located in Indian country. For example, the EPA reviewed the location of the production wells reported by facilities under the Onshore Petroleum and Natural Gas Production industry segment and found production wells reported under subpart W on lands associated with approximately 20 tribes. Therefore, although the EPA anticipates that at most only one tribe may be designated as a WEC obligated party and has the potential to be subject to the WEC, the EPA has sought opportunities to provide information to tribal governments and representatives during rule development. On November 4, 2022, the EPA published an RFI seeking public comment on a range of questions related to the Methane Emissions Reduction Program, including implementation of the WEC (see Docket ID No. EPA-HQ-OAR-2022-0875). Further, consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA specifically solicits comment on this proposed action from Tribal officials. The EPA will engage in consultation with Tribal officials during the development of this action.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2-202 of the Executive Order. This proposed action would not establish an environmental standard intended to mitigate health or safety risks and does not focus on information-gathering actions concerned with children's health. Therefore, this proposed action is not subject to Executive Order 13045. For the same reasons, the EPA's Policy on Children's Health also does not apply.

Although this proposed action does not establish an environmental standard applicable to methane emissions or mandate methane emissions reductions, it is expected that the WEC implemented under this proposed action would result in elective methane mitigation actions by applicable facilities in the oil and gas industry in order to reduce, or eliminate, the imposition of charges. As such, the EPA believes that the impacts of this proposed action would result in a reduction in an environmental health or safety risk that has a disproportionate effect on children. Accordingly, the Agency has elected to evaluate the environmental health and welfare effects of climate change on children. Greenhouse gases, including methane, contribute to climate change and are emitted in significant quantities by the oil and gas industry. The EPA believes that the implementation of the WEC in this action, if finalized, would improve children's health as a result of methane mitigation actions and operational changes taken by oil and gas applicable facilities to avoid the imposition of WEC. The assessment literature cited in the EPA's 2009 Endangerment Findings concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects (74 FR 66524, December 15, 2009). The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience (*e.g.*, the 2016 Climate and Health Assessment).[46] These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses resulting in physical and mental health effects from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with storms and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

H. Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not a “significant energy action” because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. To make this determination, we compare the projected change in crude oil and natural gas costs and production to guidance articulated in a January 13, 2021 OMB memorandum “Furthering Compliance with Executive Order 13211, Titled "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use."”[47] With respect to increases in the

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[46] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. *https://dx.doi.org/10.7930/J0R49NQX.*

[47] See *https://www.whitehouse.gov/wp-content/uploads/2021/01/M-21-12.pdf.*

cost of energy production or distribution, the guidance indicates that a regulatory action produces a significant adverse effect if it is expected to increase costs in excess of one percent. With respect to crude oil production, the guidance indicates that a regulatory action produces a significant adverse effect if it is expected to produce reductions in crude oil supply, in excess of 20 million barrels per year. With respect to natural gas production, the guidance indicates that a regulatory action produces a significant adverse effect if it reduces natural gas production in excess of 40 million thousand cubic feet (mcf) per year.[48] The economic impacts analysis conducted as part of the RIA accompanying this rulemaking estimated a maximum impact on the gas market of a 0.05 percent price increase and a 0.03 percent decrease in production. The highest impact year is estimated to be in 2026, with a production decrease of 10.7 million mcf of natural gas. The analysis projected a maximum impact on the oil market of 0.04 percent price increase and a 0.03 percent decrease in production. The highest impact year is estimated to be in 2026, with an estimated production decrease of 1.27 million barrels of oil. These impacts are substantially below the thresholds available in OMB memoranda as measures of a significant adverse effect on the energy supply. Further discussion of this analysis is available in the *Regulatory Impact Analysis of the Proposed Waste Emissions Charge,* available in the docket for this rulemaking.

I. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

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[48] The 2021 E.O. 13211 guidance memo states that the natural gas production decrease that indicates the regulatory action is a significant energy action is 40 mcf per year. Because this is a relatively small amount of natural gas and previous guidance from 2001 indicated a threshold of 25 million Mcf, we assume the 2021 memo was intended to establish 40 million mcf as the indicator of an adverse energy effect. See *https://www.whitehouse.gov/wp-content/uploads/2017/11/2001-M-01-27-Guidance-for-Implementing-E.O.-13211.pdf*.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing our Nation's Commitment to Environmental Justice for All

The EPA believes that the emissions reductions likely to result from this rule will improve health and environmental outcomes for communities facing disproportionate and adverse human health effects from the pollution subject to the waste emissions charge, including environmental justice communities. The EPA proposes, however, to determine that Executive Order 12898 does not apply to this rulemaking because it is a rule that addresses information collection, reporting procedures, and imposition of the waste emission charge directive of CAA section 136. Although the EPA anticipates a reduction in methane and associated co-pollutant emissions from this action, if finalized, these reductions are not the result of emissions standards or mandated reductions.

Although this regulation does not require action that will directly affect human health or environmental conditions, the EPA has identified and addressed environmental justice concerns by electing to conduct a qualitative assessment of the environmental justice outcomes from the proposed action. The EPA believes the human health or environmental conditions that exist prior to this proposed action would result in or have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations, and/or Indigenous peoples. The EPA identified 563 counties where Onshore Petroleum and Natural Gas Production and/or Onshore Petroleum and Natural Gas Gathering and Boosting facilities with emissions that may be above the waste emissions threshold and therefore subject to the WEC operated in 2021. These are the counties where emissions might change due to the WEC. The EPA found that there are generally higher percentages of low income and members of minority groups in these communities who may experience higher than average health risks. The EPA believes that in aggregate the proposed action will result in reduction of methane, hazardous air pollutants, and volatile organic compounds, and, generally, this result will improve environmental justice outcomes.

The information supporting this Executive Order review is contained in the *Regulatory Impact Analysis of the Proposed Waste Emissions Charge*, available in the docket for this rulemaking.

K. Determination under CAA Section 307(d)

Pursuant to CAA section 307(d)(1)(V), the Administrator determines that this proposed action is subject to the provisions of CAA section 307(d). Section 307(d)(1)(V) of the CAA provides that the provisions of CAA section 307(d) apply to "such other actions as the Administrator may determine."

List of Subjects

40 CFR Part 2

Administrative practice and procedure, Confidential business information, Courts, Environmental protection, Freedom of information, Government employees.

40 CFR Part 99

Environmental protection, Greenhouse gases, Natural gas, Petroleum, Reporting and recordkeeping requirements, Penalties.

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency proposes to amend title 40, chapter I, of the Code of Federal Regulations as follows:

PART 2—PUBLIC INFORMATION

1. The authority citation for part 2 continues to read as follows:

Authority: 5 U.S.C. 552, 552a, 553; 28 U.S.C. 509, 510, 534; 31 U.S.C. 3717.

Subpart B—Confidentiality of Business Information

2. Amend § 2.301 by revising paragraph (d) to read as follows:

§ 2.301 Special rules governing certain information obtained under the Clean Air Act.

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(d) *Data submitted under part 98 or part 99 of this chapter*—(1) Sections 2.201 through 2.215 do not apply to data submitted under part 98 or part 99 of this chapter that EPA has determined, pursuant to sections 114(c) and 307(d) of the Clean Air Act, to be either of the following:

(i) Emission data.

(ii) Data not otherwise entitled to confidential treatment pursuant to section 114(c) of the Clean Air Act.

(2) Except as otherwise provided in this paragraph (d)(2) and paragraph (d)(4) of this section, §§ 2.201 through 2.215 do not apply to data submitted under part 98 or part 99 of this chapter that EPA has determined, pursuant to sections 114(c) and 307(d) of the Clean Air Act, to be entitled to confidential treatment. EPA shall treat that information as confidential in accordance with the provisions of § 2.211, subject to paragraph (d)(4) of this section and § 2.209.

(3) Upon receiving a request under 5 U.S.C. 552 for data submitted under part 98 or part 99 of this chapter that EPA has determined, pursuant to sections 114(c) and 307(d) of the Clean Air Act, to be entitled to confidential treatment, the EPA office shall furnish the requestor a notice that the information has been determined to be entitled to confidential treatment and that

the request is therefore denied. The notice shall include or cite to the appropriate EPA determination.

(4) Modification of prior confidentiality determination. A determination made pursuant to sections 114(c) and 307(d) of the Clean Air Act that information submitted under part 98 or part 99 of this chapter is entitled to confidential treatment shall continue in effect unless, subsequent to the confidentiality determination, EPA takes one of the following actions:

(i) EPA determines, pursuant to sections 114(c) and 307(d) of the Clean Air Act, that the information is emission data or data not otherwise entitled to confidential treatment under section 114(c) of the Clean Air Act.

(ii) The Office of General Counsel issues a final determination, based on the criteria in § 2.208, stating that the information is no longer entitled to confidential treatment because of change in the applicable law or newly-discovered or changed facts. Prior to making such final determination, EPA shall afford the business an opportunity to submit comments on pertinent issues in the manner described by §§ 2.204(e) and 2.205(b). If, after consideration of any timely comments submitted by the business, the Office of General Counsel makes a revised final determination that the information is not entitled to confidential treatment under section 114(c) of the Clean Air Act, EPA will notify the business in accordance with the procedures described in § 2.205(f)(2).

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3. Add part 99 to read as follows:

PART 99—WASTE EMISSIONS CHARGE

Sec.

Subpart A—General Provisions

Authority: 42 U.S.C. 7401–7671q; 31 U.S.C. 3717.

Subpart A—General Provisions

§ 99.1 Purpose and scope.

(a) This part establishes requirements for owners and operators of certain petroleum and natural gas systems facilities to make filings and be assessed waste emission charges as required by section 136 of the Clean Air Act.

(b) Owners and operators of facilities that are subject to this part must follow the requirements of this subpart and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the applicable subpart shall take precedence.

§ 99.2 Definitions.

All terms used in this part shall have the same meaning given in the Clean Air Act, unless as defined in this section. Terms defined here only apply within the context of this rulemaking.

Act means the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq*.

Affected facility means, for the purposes of the regulatory compliance exemption of this part, affected facilities, as defined in part 60, subpart A of this chapter, that are subject to methane emissions requirements pursuant to part 60 of this chapter.

Applicable facility means a facility within one or more of the following industry segments, as those industry segment terms are defined in § 98.230 of this chapter. In the case where operations from two or more industry segments are co-located at the same part 98 reporting facility, operations for all co-located segments constitute a single *applicable facility* under this part:

(1) Offshore petroleum and natural gas production.

(2) Onshore petroleum and natural gas production.

(3) Onshore natural gas processing.

(4) Onshore natural gas transmission compression.

(5) Underground natural gas storage.

(6) Liquefied natural gas storage.

(7) Liquefied natural gas import and export equipment.

(8) Onshore petroleum and natural gas gathering and boosting.

(9) Onshore natural gas transmission pipeline.

Carbon dioxide equivalent or CO_2e means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas and is calculated using Equation A-1 in § 98.2(b) of this chapter.

Designated facility means, for purposes of the regulatory compliance exemption of this part, designated facilities, as defined in § 60.21a(b) of this chapter, subject to methane emissions requirements pursuant to a state, Tribal, or Federal plan implementing part 60 of this chapter.

e-GGRT ID number means the identification number assigned to a facility by the EPA's electronic Greenhouse Gas Reporting Tool for submission of the facility's part 98 report.

Facility applicable emissions means the annual methane emissions, as calculated in § 99.21, associated with a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the WEC applicable facility prior to consideration of any applicable exemptions.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

Global warming potential or GWP means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas (*i.e.,* CO_2). GWPs for each greenhouse gas are provided in Table A-1 of part 98, subpart A of this chapter.

Greenhouse gas or GHG means the air pollutants carbon dioxide (CO_2), hydrofluorocarbons (HFCs), methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

Nonproduction sector means facilities in the onshore natural gas processing, the liquefied natural gas storage, the liquefied natural gas import and export equipment, and the onshore petroleum and natural gas gathering and boosting industry segments as those industry segments are defined in § 98.230 of this chapter.

Onshore natural gas transmission pipeline owner or operator means, for interstate pipelines, the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, or, for intrastate pipelines, the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act, or for pipelines that fall under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994), the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224. If an intrastate pipeline is not subject to section 311 of the Natural Gas Policy Act (NGPA), the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates a facility in the onshore petroleum and/or natural gas production industry segment (as that industry segment is defined in

§ 98.230(a)(2) of this chapter). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operator means, except as otherwise defined in this section, any person who operates or supervises a facility.

Owner means, except as otherwise defined in this section, any person who has legal or equitable title to, has a leasehold interest in, or control of an applicable facility, except a person whose legal or equitable title to or leasehold interest in the facility arises solely because the person is a limited partner in a partnership that has legal or equitable title to, has a leasehold interest in, or control of the facility shall not be considered an “owner” of the facility.

Part 98 report means the annual report required under part 98 of this chapter for owners and operators of certain facilities under the Petroleum and Natural Gas Systems source category.

Petroleum means oil removed from the earth and the oil derived from tar sands and shale.

Production sector means facilities in the offshore petroleum and natural gas production and the onshore petroleum and natural gas production industry segments as those industry segments are defined in § 98.230 of this chapter.

Reporting year means the calendar year during which data are required to be collected for purposes of the annual WEC filing. For example, reporting year 2024 is January 1, 2024 through December 31, 2024, and the annual WEC filing for reporting year 2024 is submitted to EPA by March 31, 2025.

Standard temperature and pressure means 60° F and 14.7 psia.

Transmission sector means facilities in the onshore natural gas transmission compression, the underground natural gas storage, and the onshore transmission pipeline industry segments as those industry segments are defined in § 98.230 of this chapter.

Waste emissions threshold means the metric tons of methane emissions calculated by multiplying WEC applicable facility throughput by the industry segment-specific methane intensity thresholds established in CAA 136(f) and the density of methane (0.0192 metric ton per thousand standard cubic feet).

WEC means waste emissions charge, the charge established in CAA 136(c) on methane emissions that exceed certain thresholds.

WEC applicable emissions means the annual methane emissions, as calculated in § 99.21, associated with a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the WEC applicable facility after consideration of any applicable exemptions.

WEC applicable facility means an applicable facility, as defined in this section, for which the owner or operator of the part 98 reporting facility reports GHG emissions under part 98, subpart W of this chapter of more than 25,000 metric tons CO_2e.

WEC filing means the report and payment of applicable WEC obligation required to be submitted by a WEC obligated party under the requirements of this chapter. The WEC filing contains information regarding the WEC obligated party and WEC applicable facilities for the previous reporting year. For example, the WEC filing due on March 31, 2025 contains information regarding reporting year 2024, which is January 1, 2024 through December 31, 2024.

WEC obligated party means the owner or operator as defined in this section for the applicable industry segment as of December 31 of the reporting year. In cases where a WEC applicable facility has more than one owner or operator, the WEC obligated party shall be a person or entity selected by an agreement binding on each of the owners and operators involved in the transaction, following the provisions of § 99.4(b).

WEC obligation means the WEC charge amount resulting from the calculations in § 99.23.

You means a WEC obligated party subject to this part 99.

§ 99.3 Who must file?

WEC obligated parties, as defined in § 99.2, are required to submit a WEC filing and remit applicable WEC obligations and charges.

§ 99.4 How do I authorize and what are the responsibilities of the designated representative?

Each WEC obligated party must follow the procedures in paragraphs (a) through (l) of this section, as applicable, to identify a WEC obligated party designated representative. In cases where a WEC applicable facility has more than one owner or operator, the WEC obligated party shall be a person or entity selected by an agreement binding on each of the owners and operators involved in the transaction, following the provisions of paragraph (b) of this section. Failure to select a WEC obligated party for each WEC applicable facility with multiple owners or operators following the procedures of paragraph (b) of this section is considered a violation of this part for each owner and operator (as defined in § 99.2 of this part) for the applicable industry segment of the associated WEC applicable facility.

(a) *General*. Except as provided under paragraph (f) of this section, each WEC obligated party that is subject to this part shall have one designated representative, who shall be responsible for certifying, signing, and submitting WEC filings or other submissions to the Administrator under this part.

(b) *Authorization of a designated representative*. The designated representative of each WEC obligated party shall be an individual selected by an agreement binding on the owner and operator of such entity and shall act in accordance with the certification statement in paragraph (i)(3)(iv) of this section. Failure of a WEC obligated party to authorize a designated representative following the procedures of this section is considered a violation of this part.

(c) *Responsibility of the designated representative*. Upon receipt by the Administrator of a complete certificate of representation under this section for the WEC obligated party, the designated representative identified in such certificate of representation shall represent and, by his or her representations, actions, inactions, or submissions, legally bind the owner and operator of such an entity in all matters pertaining to this part, notwithstanding any agreement between the designated representative and said owner and operator. The owner and operator shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) *Timing*. No WEC filing or other submissions under this part for a WEC obligated party will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the WEC obligated party. Such certificate of representation shall be submitted at least 60 days before the deadline for submission of the WEC obligated party's WEC filing under § 99.5.

(e) *Certification of the WEC filing*. Each WEC filing and any other submission under this part for a WEC obligated party shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the WEC obligated party in accordance with this section and § 3.10 of this chapter.

(1) Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owner and operator of the WEC obligated party, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) The Administrator will accept a WEC filing or other submission for a WEC obligated party under this part only if the submission is certified, signed, and submitted in accordance with this section.

(f) *Alternate designated representative*. A certificate of representation under this section for the WEC obligated party may designate one alternate designated representative, who shall be an individual selected by an agreement binding on the owner and operator, and may act on behalf of the WEC obligated party designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) Upon receipt by the Administrator of a complete certificate of representation under this section for a WEC obligated party identifying an alternate designated representative, the following apply.

(i) The alternate WEC obligated party designated representative may act on behalf of the WEC obligated party designated representative.

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the WEC obligated party designated representative.

(2) Except in this section, whenever the term “designated representative” is used in this part, the term shall be construed to include the designated representative or any alternate designated representative.

(g) *Changing a designated representative or alternate designated representative*. The designated representative or alternate designated representative identified in a complete certificate of representation under this section for a WEC obligated party received by the Administrator may be changed at any time upon receipt by the Administrator of another later signed, complete certificate of representation under this section for the WEC obligated party. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative or the previous alternate designated representative of the WEC obligated party before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owner and operator of the WEC obligated party.

(h) *Changes in the WEC obligated party*. Within 90 days after any change in the WEC obligated party, the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section to reflect the change.

(i) *Certificate of representation*. A certificate of representation shall be complete if it includes the following elements in a format prescribed by the Administrator in accordance with this section:

(1) Identification of the WEC obligated party for which the certificate of representation is submitted.

(2) The name, organization name (company affiliation-employer), address, e-mail address, telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) The following certification statements by the designated representative and any alternate designated representative:

(i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owner and operator of the entity.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 99 on behalf of the owner and operator of the entity and that such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”

(iii) “I certify that the owner and operator of the entity, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the entity.”

(iv) “If there are multiple owners and operators of the entity, I certify that I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the entity.”

(4) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) *Documents of agreement*. Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) *Binding nature of the certificate of representation*. Once a complete certificate of representation under this section for a WEC obligated party has been received, the Administrator will rely on the certificate of representation unless and until a later signed, complete certificate of representation under this section for the facility is received by the Administrator.

(l) Objections concerning a designated representative.

(1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

§ 99.5 When must I file and remit the applicable WEC obligation?

Each WEC obligated party must submit their WEC filing including the information specified in § 99.7 and remit applicable WEC obligation no later than March 31 of the year following the reporting year. All filing revisions must be received according to the schedule in § 99.7(e) to be considered for revisions to WEC obligations. If the submission date falls on a weekend or a federal holiday, the submission date shall be extended to the next business day.

§ 99.6 How do I file?

Each WEC filing, certificate of representation, and remittance of applicable WEC fees for the WEC obligated party must be submitted electronically in accordance with the requirements of this part and in a format specified by the Administrator.

§ 99.7 What are the general reporting, recordkeeping, and verification requirements of this part?

The WEC obligated party that is subject to the requirements of this part must submit a WEC filing to the Administrator as specified in this section.

(a) *Schedule*. The WEC filing must be submitted in accordance with § 99.5.

(b) *Content of the WEC filing*. For each WEC obligated party, report the information in paragraphs (b)(1)(i) through (v) of this section. For each WEC applicable facility under common ownership or control of the WEC obligated party, report the information in paragraphs (b)(2)(i) through (vii) of this section. The WEC filing must also include payment of applicable WEC obligation, as specified in paragraph (b)(3) of this section.

(1) Reporting requirements at the WEC obligated party level.

(i) The company name.

(ii) The United States address for the company.

(iii) The name, address, e-mail address, and phone number for the designated representative for the WEC obligated party.

(iv) The list of e-GGRT ID number(s) under which the WEC applicable facilities comprising the WEC obligated party as of December 31 of the reporting year report under part 98, subpart W of this chapter.

(v) The net WEC emissions, as calculated pursuant to § 99.22, and WEC obligation, as calculated pursuant to § 99.23, for the WEC obligated party.

(2) Reporting requirements for each WEC applicable facility comprising the WEC obligated party.

(i) The e-GGRT ID under which the WEC applicable facility emissions are reported under part 98, subpart W of this chapter.

(ii) The industry segment(s) for the WEC applicable facility.

(iii) For WEC applicable facilities in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment as defined in § 99.2, if conditions specified in § 99.30 regarding emissions from delays in permitting are met, provide information as specified in § 99.31.

(iv) If the conditions specified in § 99.40 are met regarding the regulatory compliance exemption, report whether the WEC applicable facility contains any affected facilities under part 60 of this chapter or any designated facilities under an applicable approved state, Tribal, Federal plan in part 62 of this chapter. If so, provide the information specified in § 99.41, as applicable.

(v) For WEC applicable facilities in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment as defined in § 99.2, if conditions specified in § 99.50 regarding emissions from permanently shut-in and plugged wells are met, you must report the information specified in § 99.51.

(vi) The facility waste emissions threshold as calculated pursuant to § 99.20, and, if there is more than one applicable industry segment within the WEC applicable facility, each industry segment waste emissions threshold for each applicable industry segment within the applicable facility, as calculated pursuant to § 99.20,

(vii) The facility applicable emissions, as calculated pursuant to § 99.21 and the WEC applicable emissions, as calculated pursuant to § 99.21.

(3) Payment of applicable WEC obligation, submitted in accordance with § 99.9.

(c) *Verification of the WEC filing*. To verify the completeness and accuracy of WEC filing, the EPA will consider the verification status of part 98 reports, and may review the certification statements described in § 99.4 and any other credible evidence, in conjunction with a comprehensive review of the WEC filing, including attachments. The EPA may conduct audits of selected WEC obligated parties and associated WEC applicable facilities. During such audits, the records generated under this part must be made available to the EPA. The on-site audits may be conducted by private auditors contracted by the EPA or by Federal, State or local personnel, as appropriate, and may be required to be arranged by and conducted at the expense of the WEC obligated party. Nothing in this section prohibits the EPA from using additional information, including reports, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, orFederal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, to verify the completeness and accuracy of the filings.

(d) *Recordkeeping*. Retain all required records for at least 5 years from the date of submission of the WEC filing for the reporting year in which the record was generated. The records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. Upon request by the Administrator, the records required under this section must be made available to EPA. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records:

(1) All information required to be retained by part 98, subparts A and W of this chapter.

(2) Any other information not included in a part 98 report used to complete the WEC filing.

(3) All information required to be submitted as part of the WEC filing.

(e) *Annual WEC filing revisions*. Except as specified in paragraph (e)(2) of this section, the provisions of this paragraph (e) apply until November 1 of the year following the reporting year, or for a given reporting year after the November 1 deadline if the resubmission is related to the resolution of unverified data process specified at § 99.8.

(1) The WEC obligated party shall submit a revised WEC filing within 45 days of discovering that a previously submitted WEC filing contains one or more substantive errors. The revised WEC filing must correct all substantive errors. If the resubmission is due to a correction in a part 98 report resubmitted by a WEC applicable facility, the WEC obligated party must report the number of corrections made in the part 98 report(s) and a description of how the changes impact the assessment of the WEC obligation.

(2) The revisions for substantive errors as described in paragraph (e)(2)(i) and (ii) are not subject to the November 1 deadline and must be submitted according the schedule therein.

(i) Revised filings for purposes of the regulatory compliance exemption must be submitted as follows:

(A) Revised filings to submit a CAA section 111(b) or (d) compliance report which covers the remaining portion of a WEC filing year, which were not available at the time of the WEC filing, must be submitted on or before the date that the compliance report covering the remainder of the year is due under the applicable requirements of CAA section 111(b) or (d), as applicable.

(B) Revised filings to submit findings by the WEC obligated party that one or more deviations or violations discovered after the WEC filing must be submitted within 45 days of the discovery.

(ii) The Administrator may notify the WEC obligated party in writing that a WEC filing previously submitted by the owner or operator contains one or more substantive errors. Such notification will identify each such substantive error. The WEC obligated party shall, within 45 days of receipt of the notification, either resubmit the WEC filing that, for each identified substantive error, corrects the identified substantive error (in accordance with the applicable requirements of this part) or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error. The EPA reserves to right to revise WEC obligations for a given reporting year after the November 1 final resubmission deadline if data errors are discovered by EPA at a later date.

(3) A substantive error is an error that impacts the Administrator's ability to accurately calculate a WEC obligated party's WEC obligation, which may include, but is not limited to, the list of WEC applicable facilities associated with a WEC obligated party, the emissions or throughput reported in the WEC applicable facility part 98 report(s), emissions associated with exemptions, and supporting information for each exemption to demonstrate its validity.

(4) Notwithstanding paragraphs (e)(1) and (2) of this section, upon request the Administrator may provide an extension of the 45-day period for submission of a revised report or information under paragraphs (e)(1) and (2) of this section if adequate justification is provided by the WEC obligated party. The Administrator may provide an extension of up to 30 days provided that the request is received by email to an address prescribed by the Administrator prior to the expiration of the 45-day period and that the request demonstrates that it is not practicable to submit a revised report or information under paragraphs (e)(1) and (2) of this section within 45 days.

(5) The WEC obligated party shall retain documentation for 5 years to support any revision made to a WEC filing.

(6) If a facility changes ownership such that there is a change to the WEC obligated party, the entity that was the WEC obligated party at the time of the original filing for a reporting year remains responsible for any revisions to WEC filings for that reporting year.

(f) *Designation of unverified filings and reports*. Following the verification process discussed in § 98.3(h) of this chapter for part 98 reports and paragraph (c) of this section for WEC filings, the EPA shall designate:

(1) The annual part 98 report associated with each WEC applicable facility as either verified or unverified. An unverified report is one in which the EPA has provided notification under § 98.3(h)(2) of this chapter and the owner or operator of the WEC applicable facility has failed to revise and resubmit the report and resolve the error or provide justification to the satisfaction of the EPA that the identified error is not a substantive error (in accordance with the applicable requirements of § 98.3(h)(3) of this chapter).

(2) The annual WEC filing from each WEC obligated party submitted pursuant to § 99.7 as either verified or unverified. An unverified filing is one in which the EPA has provided notification under § 99.7(e)(2) and the WEC obligated party designated representative has failed to resubmit the report and for each identified substantive error correct the identified substantive error (in accordance with the applicable requirements of paragraph (e)(3) of this section) or provide information demonstrating that the submitted report does not contain the identified substantive error or that the identified error is not a substantive error. The determination of verification status of a part 98 report under paragraph (f)(1) of this section will be taken into consideration in the determination of the verification status of a WEC filing.

§ 99.8 What are the general provisions for assessment of the WEC obligation?

(a) *Assessment of the WEC obligation*. WEC obligation assessments shall be made pursuant to § 99.23 on the basis of information submitted by the date specified in § 99.5 and following the submittal requirements of § 99.6.

(b) *Assessment of the WEC obligation for unverified filings*. If a WEC filing is unverified but the EPA is able to correct the error(s) based on reported data, the EPA will recalculate the WEC using available information and provide an invoice or refund to the WEC obligated party within 60 days of determining a WEC filing to be unverified. If the WEC obligated party resubmits a WEC filing within that timeframe, the EPA will either verify the resubmission, or take the resubmission into account when calculating the WEC.

(c) *Third-party audits for unverified reports*. If the EPA is unable to calculate the WEC with available information, the EPA may require the WEC obligated party to undergo a third party audit. The EPA may require the WEC obligated party to fund and arrange the third-party audit. The third-party auditor must review records kept by the WEC obligated party, quantify the WEC with available information, and the updated WEC calculations and supporting data must be submitted to the EPA. The EPA will then take that information into consideration and calculate the WEC and provide an invoice or refund to the WEC obligated party.

(1) *Third party reviews*. An independent third-party audit of the information provided shall be based on a review of the relevant documents and shall identify each item required by the WEC filing, describe how the independent third-party evaluated the accuracy of the information provided, state whether the independent third-party agrees with the information provided, and identify any exceptions between the independent third-party's findings and the information provided.

(i) Audits required under this section must be conducted by a certified independent third-party. The auditor must have professional work experience in the petroleum engineering field or related to oil and gas production, gathering, processing, transmission or storage.

(ii) To be considered an independent third-party, the independent third party shall not be operated by the WEC obligated party and the independent third party shall be free from any interest in the WEC obligated party’s business.

(iii) The independent third-party shall submit all records pertaining to the audit required under this section, including information supporting all of the requirements of § 99.8(c)(1) to the WEC obligated party.

(iv) The independent third-party must provide to the WEC obligated party documentation of qualifications of professional work experience in the petroleum engineering field or related to oil and gas production, gathering, processing, transmission or storage.

(2) *Reporting and recordkeeping requirements for WEC obligated parties following third party audits*.

(i) The WEC obligated party shall provide to EPA the results of the third-party audit, including the WEC obligation amount and all supporting documentation information that is included in reporting requirements under §§ 99.7, and 99.31, 99.41, and 99.51, as applicable.

(ii) The WEC obligated party shall provide to EPA documentation of qualifications of the third-party auditor.

(iii) The WEC obligated party shall retain all records pertaining to the audit required under this section for a period of 5 years from the date of creation and shall deliver such records to the Administrator upon request.

(d) *Resubmittal of filings and reports for the current or prior reporting year*. If resubmittal of a previously submitted part 98 report and/or WEC filing, submitted as specified in §99.7(e), results in a change to the WEC obligation determined for a WEC obligated party for the reporting yearthe following process shall apply:

(1) If the WEC obligation based upon the resubmitted report or filing for the reporting year is less than the WEC obligation previously remitted by the WEC obligated party, the Administrator shall authorize a refund to the WEC obligated party equal to the difference in WEC obligation.

(2) If the WEC obligation based upon the resubmitted report or filing for the reporting year is greater than the WEC obligation previously remitted by the WEC obligated party, the

Administrator shall issue an invoice to the WEC obligated party containing a charge in the amount determined using Equation A-1 of this section. Interest shall not be assessed for a change in WEC obligation resulting from the timely submittal of a regulatory report in accordance with § 99.41(c).

$$WEC_r = \Delta WEC \times \left(1 + \frac{i_{CVFR}}{365}\right)^t \qquad \text{(Eq. A-1)}$$

Where:

WEC_r = The charge obligation of the WEC obligated party to be resubmitted for the difference in WEC obligation, including any applicable interest, in dollars.

ΔWEC = The difference in WEC obligation, calculated as the amount remitted upon the original submittal specified in § 99.5 subtracted from the quantity of WEC obligation determined based upon the resubmitted report or filing, in dollars.

i_{CVFR} = The Treasury Current Value of Funds Rate as specified in § 99.10(b).

t = The number of days after the deadline specified in § 99.5 for remittance of WEC obligation for the reporting year that the resubmitted WEC filing or part 99 report was received by the Administrator, in days. For example, if a reporting year 2024 part 99 report is resubmitted on April 28, 2025, “t” is equal to 28 days. If a reporting year 2024 part 99 report is resubmitted on April 28, 2026, “t” is equal to 393 days.

365 = Conversion factor from years to days.

§ 99.9 How are payments required by this part made?

(a) The WEC obligation owed for each reporting year must be paid by the WEC obligated party as part of the annual WEC filling, as required by § 99.7(b), and is considered due at the date specified in § 99.5.

(b) Other than the WEC obligation specified in paragraph (a) of this section, all other charges required by this part, including adjusted WEC obligations, interest fees, and penalties, shall be paid by the WEC obligated party in response to an electronic invoice or bill by the specified due date, or within 30 days of the date of the invoice or bill if a due date is not provided.

(c) All WEC obligations, interest fees, and penalties required by this subpart shall be paid to the Department of the Treasury by the WEC obligated party electronically in U.S. dollars, using an online electronic payment service specified by the Administrator.

§ 99.10 What fees apply to delinquent payments?

(a) *Delinquency*. WEC obligated party accounts are delinquent if the WEC obligation payment is not submitted in full by the date required by § 99.5. WEC obligated party accounts are also delinquent if the accounts remain unpaid after the due date specified in the invoice or other notice of the WEC amount owed.

(b) *Interest fee*. In accordance with 31 U.S.C. 3717(a), delinquent WEC obligated party accounts shall be charged a minimum annual rate of interest equal to the average investment rate for Treasury tax and loan accounts (Current Value of Funds Rate or CVFR) most recently published and in effect by the Secretary of the Treasury.

(c) *Non-payment penalty*. In accordance with 31 U.S.C. 3717(e), WEC obligated party accounts that are more than 90 days past due shall be charged an additional penalty of 6% per year assessed on any part of the debt that is past due for more than 90 days.

(d) *Penalty for non-submittal*. In accordance with 42 U.S.C. 7413(d)(1), a WEC obligated party that fails to submit an annual WEC filing by the date specified in § 99.5 may be charged an administrative penalty. The penalty assessment shall be a daily assessment per day that the WEC filing is not submitted, assessed up to the value specified in Table 1 of § 19.4, as amended, of this chapter. The assessment of penalty shall begin on the date that the WEC filing was considered past due per § 99.5 and continue until such time that the WEC filing is submitted by the WEC obligated party's designated representative.

§ 99.11 What are the compliance and enforcement provisions of this part?

Any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. 7414) and section 136 (42 U.S.C. 7436). A violation would include, but is not limited to, failure to submit a WEC filing, failure to collect data needed to calculate the WEC charge (including any data relevant to determining the applicability of any exemptions), failure to select a WEC obligated party, failure to retain records needed to verify the amount of WEC charge, providing false information in a WEC filing, and failure to remit WEC payment. Each day of a violation would constitute a separate violation. Each day of each violation constitutes a separate violation. Any penalty assessed shall be in addition to any WEC obligation due under this part and any fees applicable to delinquent payments due under § 99.10.

§ 99.12 What addresses apply for this part?

All requests, notifications, and communications to the Administrator pursuant to this part must be submitted electronically and in a format as specified by the Administrator.

§ 99.13 What are the confidentiality determinations and related procedures for this part?

This section characterizes various categories of information for purposes of making confidentiality determinations, as follows:

(a) This paragraph (a) applies the definition of “Emission data” in 40 CFR 2.301(a) for information reported under this part. “Emission data” cannot be treated as confidential business information and shall be available to be disclosed to the public. The following categories of information qualify as emission data:

(1) Methane emission information, including the net WEC emissions, waste emissions thresholds, WEC applicable emissions, and the quantity of methane emissions to be exempted due to unreasonable delay and wells that were permanently shut-in and abandoned.

(2) Calculation methodology, including the method used to determine the quantity of methane emissions to be exempted due to an unreasonable permitting delay and the method used to quantify emissions exempted from permanently shut-in and plugged wells.

(3) Facility and unit identifier information, including WEC obligated party company name and address, the name and contact information for the designated representative of WEC obligated party, signed and dated certification statements of the accuracy and completeness of the report, facility identifiers (*e.g.*, e-GGRT ID number), industry segment, well-pad and/or well

identifiers, and emission source-specific methane mitigation activities impacted by an unreasonable permitting delay.

(b) The following types of information are not eligible for confidential treatment:

(1) The WEC obligation, as calculated pursuant to § 99.23.

(2) Compliance information, including information regarding applicable emissions standards or other relevant standards of performance or requirements, information in construction or operating permits, and information submitted to document compliance with an emissions standard or a standard of performance, such as a periodic report, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, orFederal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, (excluding any information redacted from the report and claimed as confidential).

(3) Published information that is publicly available, including information that is made available through publication of annual reports submitted under part 98 of this chapter, on company or other websites, or otherwise made publicly available.

(c) If you submit information that is not described in paragraphs (a) and (b) of this section, you may claim the information as confidential and the information is subject to the process for confidentiality determinations in 40 CFR part 2 as described in §§ 2.201 through 2.208. We may require you to provide us with information to substantiate your claims. If claimed, we may consider this substantiating information to be confidential to the same degree as the information for which you are requesting confidential treatment. We will make our determination based on your statements to us, the supporting information you send us, and any other available information. However, we may determine that your information is not subject to confidential treatment consistent with 40 CFR part 2 and 5 U.S.C. 552(b)(4).

(d) Submitted applications and reports typically rely on software or templates to identify specific categories of information. If you submit information in a comment field designated for users to add general information, we will respond to requests for disclosing that information consistent with paragraphs (a) through (c) of this section.

Subpart B—Determining Waste Emissions Charge

§ 99.20 How will the waste emissions threshold for each WEC applicable facility be determined?

The methane waste emissions threshold for each applicable industry segment within a WEC applicable facility for the reporting year will be calculated as described in paragraphs (a) through (d) of this section, as applicable. The methane waste emissions threshold for each WEC applicable facility will be determined as described in paragraph (e) of this section.

(a) For each offshore petroleum and natural gas production industry segment or onshore petroleum and natural gas production industry segment that sends natural gas to sale at a WEC applicable facility, the facility waste emissions threshold will be calculated using Equation B-1 of this section.

$$TH_{is,Prod} = 0.002 \times \rho_{CH_4} \times Q_{ng,Prod} \qquad \text{(Eq. B-1)}$$

Where:

$TH_{is,Prod}$ = The methane waste emissions threshold for the industry segment at a WEC applicable facility for the reporting year in the production sector that has natural gas sent to sale, metric tons (mt) CH_4.

0.002 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for methane emissions for applicable facilities with natural gas sales in the production sector, thousand standard cubic feet (Mscf) CH_4 per Mscf of natural gas sent to sale.

ρ_{CH4} = Density of methane = 0.0192 kilograms per standard cubic foot (kg/scf) = 0.0192 metric tons per thousand standard cubic feet (mt/Mscf).

$Q_{ng,Prod}$ = The total quantity of natural gas that is sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to part 98, subpart W of this chapter. For onshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(1)(i)(B) of this chapter, in Mscf. For offshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(2)(i) of this chapter, in Mscf.

(b) For each offshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas production industry segment that has no natural gas sent to sale at a WEC applicable facility, the facility waste emissions threshold will be calculated using Equation B-2 of this section.

$$TH_{is,Prod} = 10 \times Q_{o,Prod} \times 10^{-6} \qquad \text{(Eq. B-2)}$$

Where:

$TH_{is,Prod}$ = The annual methane waste emissions threshold for the industry segment at a WEC applicable facility in the production sector that has no natural gas sent to sale, mt CH_4.

10 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for applicable facilities with no natural gas sales in the production sector, mt CH_4 per million barrels oil sent to sale.

$Q_{o,Prod}$ = The total quantity of crude oil that is sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to part 98, subpart W of this chapter. For onshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(1)(i)(C) of this chapter, in barrels. For offshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(2)(ii) of this chapter, in barrels.

10^{-6} = Conversion from barrels to million barrels.

(c) For each onshore natural gas processing industry segment, liquefied natural gas storage industry segment, the liquefied natural gas import and export equipment industry segment, or the onshore petroleum and natural gas gathering and boosting industry segment at a WEC applicable facility, the facility waste emissions threshold will be calculated using Equation B-3 of this section.

$$TH_{is,NonProd} = 0.0005 \times \rho_{CH_4} \times Q_{ng,NonProd} \qquad \text{(Eq. B-3)}$$

Where:

$TH_{is,NonProd}$ = The annual methane waste emissions threshold for the industry segment at a WEC applicable facility in the nonproduction sector, mt CH_4.

0.0005 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for applicable facilities in the nonproduction sector, Mscf CH_4 per Mscf of natural gas sent to sale from or through the facility.

ρ_{CH4} = Density of methane = 0.0192 kg/scf = 0.0192 mt/Mscf.

$Q_{ng,NonProd}$ = The total quantity of natural gas that is sent to sale from or through the industry segment at a WEC applicable facility in the reporting year as reported pursuant to part 98, subpart W of this chapter. For RY 2024 for onshore natural gas processing, you must use the quantity reported pursuant to § 98.236(aa)(3)(ii) of this chapter, in Mscf and for RY 2025 and later, you must use the quantity reported pursuant to proposed § 98.236(aa)(3)(ix) of this chapter, in Mscf. For LNG import and export, you must use sum of the quantities reported pursuant to § 98.236(aa)(6) and (7) of this chapter, in Mscf. For LNG storage, you must use the quantity reported pursuant to § 98.236(aa)(8)(ii) of this chapter, in Mscf. For onshore petroleum and natural gas gathering and boosting, you must use the quantity reported pursuant to § 98.236(aa)(10)(ii) of this chapter, in Mscf .

(d) For each onshore natural gas transmission compression industry segment, underground natural gas storage industry segment, or onshore natural gas transmission pipeline industry segment at a WEC applicable facility, the facility waste emissions threshold will be calculated using Equation B-4 of this section.

$$TH_{is,Tran} = 0.0011 \times \rho_{CH_4} \times Q_{ng,Tran} \qquad \text{(Eq. B-4)}$$

Where:

$TH_{is,Tran}$ = The annual methane waste emissions threshold for the industry segment at a WEC applicable facility in the transmission sector, mt CH_4.

0.0005 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for applicable facilities in the transmission sector, Mscf CH_4 per Mscf of natural gas sent to sale from or through the facility.

ρ_{CH4} = Density of methane = 0.0192 kg/scf = 0.0192 mt/Mscf.

$Q_{ng,Tran}$ = The total quantity of natural gas that is sent to sale from or through the industry segment at a WEC applicable facility in the reporting year as reported pursuant to part 98, subpart W of this chapter. For onshore natural gas transmission compression, you must use the quantity reported pursuant to § 98.236(aa)(4)(i) of this chapter, in Mscf. For underground natural gas storage, you must use the quantity reported pursuant to § 98.236(aa)(5)(ii) of this chapter, in Mscf. For onshore natural gas transmission pipeline, you must use the quantity reported pursuant to § 98.236(aa)(11)(iv) of this chapter, in Mscf.

(e) For each WEC applicable facility that operates in a single industry segment, the methane waste emissions threshold shall be equal to the value calculated in Equation B-1, Equation B-2, Equation B-3, or Equation B-4 of this section, as applicable. For each WEC applicable facility that operates in two or more industry segments, the facility waste emissions threshold will be calculated using Equation B-5 of this section.

$$TH_{WAF} = \sum_{s=1}^{N} TH_{is,s} \text{(Eq. B-5)}$$

Where:

TH_{WAF} = The WEC applicable facility waste emissions threshold, mt CH4.

$TH_{is,s}$ = The industry segment waste emissions threshold, as calculated in Equation B-3 or Equation B-4 of this section, for each industry segment "s" at the WEC applicable facility, mt CH_4.

N = Number of industry segments at the WEC applicable facility.

§ 99.21 How will the WEC applicable emissions for a WEC applicable facility be determined?

(a) The total facility applicable emissions for each WEC applicable facility will be calculated using Equation B-6 of this section.

$$E_{TFA,CH_4} = E_{SubpartW,CH_4} - TH_{WAF} \qquad \text{(Eq. B-6)}$$

Where:

$E_{TFA,CH4}$ = The annual methane emissions equal to, below, or exceeding the waste emissions threshold for a WEC applicable facility prior to consideration of any applicable exemptions (*i.e.*, total facility applicable emissions), mt $CH_{4.}$

$E_{SubpartW,CH4}$ = The annual methane emissions for a WEC applicable facility, as reported under part 98, subpart W of this chapter for the corresponding reporting year, mt $CH_{4.}$

TH_{WAF} = The waste emissions threshold for a WEC applicable facility, as determined in § 99.20(e), mt CH_4.

(b) If the total facility applicable emissions calculated using Equation B-6 of this section are less than or equal to 0 mt, then the WEC applicable emissions are equal to the total facility applicable emissions.

(c) If the total facility applicable emissions calculated using Equation B-6 of this section are greater than 0 mt and the regulatory compliance exemption as specified in § 99.40 applies to the WEC applicable facility, the WEC applicable emissions for that facility are equal to 0 mt.

(d) If the total facility applicable emissions calculated using Equation B-6 of this section are greater than 0 mt and the regulatory compliance exemption as specified in § 99.40 does not apply to the WEC applicable facility, the WEC applicable emissions for each WEC applicable facility will be calculated using Equation B-7 of this section.

$$E_{WA,CH_4} = E_{TFA,CH_4} - E_{Delay,CH_4} - E_{Plug,CH_4} \quad \text{(Eq. B-7)}$$

Where:

$E_{WA,CH4}$ = The annual methane emissions associated with a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the WEC applicable facility (i.e., the WEC applicable emissions) , mt CH_4. If the result of this calculation is less than 0 mt CH_4, the WEC appliable emissions for the facility are equal to 0 mt CH_4.

$E_{TFA,CH4}$ = The annual methane emissions equal to, below, or exceeding the waste emissions threshold for a WEC applicable facility prior to consideration of any applicable exemptions for the reporting year, mt CH_4.

$E_{Delay,CH4}$ = The quantity of methane emissions exempted, as determined in Equation C-1 of § 99.32, at the WEC applicable facility in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment due to an unreasonable delay in environmental permitting of gathering or transmission infrastructure, mt CH_4.

$E_{Plug,CH4}$ = The total quantity of annual methane emissions, as determined in Equation E-5 of § 99.52, at the WEC applicable facility in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments, attributable to all wells that were permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements, mt CH_4.

§ 99.22 How will the net WEC emissions for a WEC obligated party be determined?

Net WEC emissions for a WEC obligated party, equal to the sum of WEC applicable emissions from all facilities with the same WEC obligated party, as specified in 99.2, will be calculated using Equation B-8 of this section.

$$E_{NetWEC,CH_4} = \sum_{j=1}^{N} E_{WA,CH_4} \text{(Eq. B-8)}$$

Where:

$E_{NetWEC,CH4}$ = The annual methane emissions subject to the WEC for the WEC obligated party for the reporting year, mt CH_4.

$E_{WA,CH4}$ = The annual methane emissions equal to, below, or exceeding the waste emissions thresholds for a WEC applicable facility “j” as calculated in § 99.21(b) or (d) under common ownership or control of a WEC obligated party, mt CH_4.

N = Total number of WEC applicable facilities under common ownership or control of a WEC obligated party, excluding any WEC applicable facilities for which the regulatory compliance exemption as specified in § 99.40 applies.

§ 99.23 How will the WEC Obligation for a WEC obligated party be determined?

(a) If the net WEC emissions for a WEC obligated party as determined in § 99.22 are less than or equal to zero, the WEC obligated party’s WEC obligation is zero and the WEC obligated party is not subject to a waste emissions charge in the reporting year.

(b) If the net WEC emissions for a WEC obligated party as determined in § 99.22 are greater than zero, the WEC obligation will be calculated according to the applicable provisions in paragraphs (b)(1) through (3) of this section.

(1) For reporting year 2024, multiply the net WEC emissions from Equation B-8 of this subpart by $900 per mt CH_4 to determine the WEC obligation.

(2) For reporting year 2025, multiply the net WEC emissions from Equation B-8 of this subpart by $1,200 per mt CH_4 to determine the WEC obligation.

(3) For reporting year 2026 and each year thereafter, multiply the net WEC emissions from Equation B-8 of this subpart by $1,500 per mt CH_4 to determine the WEC obligation.

Subpart C—Unreasonable Delay Exemption

§ 99.30 Which facilities qualify for the exemption for emissions caused by an unreasonable delay in environmental permitting of gathering or transmission infrastructure?

(a) The WEC applicable facility must be in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment as defined in § 99.2.

(b) The total facility applicable emissions for the WEC applicable facility as calculated in accordance with § 99.21(a) must exceed 0 mt.

(c) All requests for information regarding the permit received by either the production entity potentially eligible for the exemption or the entity seeking the environmental permit must not have exceeded the response time requested by the permitting agency, or by the relevant production or gathering or transmission infrastructure entity seeking the permit, or exceeded 30 days if no specific response time is requested.

(d) The WEC facility must report flaring emissions in the reporting year that occurred as a result of a delay in environmental permitting of gathering or transmission infrastructure, and are in compliance with all applicable local, state and federal regulations regarding flaring emissions.

(e) [A set period of months (with exact timing to be specified at final)] must have passed since submission of a complete environmental permit application, as certified by the relevant permitting authority, to construct gathering or transmission infrastructure without approval or denial of the environmental permit application.

§ 99.31 What are the reporting requirements for the exemption for emissions caused by an unreasonable delay in environmental permitting of gathering or transmission infrastructure?

(a) Upon meeting all criteria in § 99.30(a) through (f), you shall report information regarding an exemption for unreasonable delay in permitting of gathering or transmission infrastructure for a given reporting year. The unreasonable delay exemption information to be reported is described in paragraph (b) of this section. The unreasonable delay exemption shall be submitted as described in paragraph (c) of this section.

(b) For each unreasonable delay exemption, the WEC obligated party must report the information specified in paragraphs (b)(1) through (10) of this section.

(1) The company name and name of the facility that submitted the permit application to construct and/or operate gathering or transmission infrastructure.

(2) The name and e-GGRT ID number under part 98, subpart W of this chapter of the production facility impacted by the unreasonable delay in environmental permitting of gathering or transmission infrastructure.

(3) The date of the initial permit request to build gathering or transmission infrastructure.

(4) An attestation that the entity seeking the permit has been responsive to the relevant authority regarding the permit application, that is that the entity has responded to all requests from the permitting authority within the time frame requested by the relevant authority or within 30 days if no timeframe is specified.

(5) For each well-pad impacted by the unreasonable delay in permitting of gathering or transmission infrastructure:

(i) The well-pad ID for each well-pad, as reported under part 98, subpart W of this chapter.

(ii) A listing of methane emissions mitigation activities that are impacted by the unreasonable permitting delay.

(6) The estimated date to commence operation of the gathering or transmission infrastructure if application had been approved before [the set period of months elapsed (exact timing to be specified at final)].

(7) If the application has been approved and operations commenced during the reporting year, the first date that offtake to the gathering or transmission infrastructure from the implementation of methane emissions mitigation occurred.

(8) The beginning and ending date for which the eligible delay limited the offtake of Nnatural gas associated with methane emissions mitigation activities for the reporting year as determined according to § 99.32(a).

(9) The quantity of methane emissions to be exempted due to the unreasonable delay for the reporting year calculated as specified in § 99.32 and the method used to determine the quantity of methane emissions to be exempted (used § 99.32(b)(1); used § 99.32(b)(2)(i); used § 99.32(b)(2)(ii) with K_f based on volume; used § 99.32(b)(2)(ii) with K_f based on time).

(10) Information on all applicable local, state, and federal regulations regarding flaring emissions and the facility's compliance status for each.

(11) For each permit relevant to the exemption, the name/type of permit, permitting agency, and a link to information on the permit (e.g., available through the permitting agency), if available.

(c) Each submittal under this section shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the WEC obligated party in accordance with this section and § 3.10 of this chapter.

§ 99.32 How are the methane emissions caused by an unreasonable delay in environmental permitting of gathering or transmission infrastructure quantified?

(a) Determine the time period associated with the emissions that occurred as a result of the eligible delay within the reporting year as specified in paragraphs (a)(1) and (2) of this section.

(1) The start date of the emissions caused by the delay in the reporting year is the latter of January 1 of the reporting year, or the date on which emissions would have been avoided through commencement of the operation of the gathering or transmission infrastructure if the application to construct and/or operate the gathering or transmission infrastructure had been approved within a set period of months as specified in § 99.31(b)(6).

(2) The end time of the emissions caused by the delay in the reporting year is the earlier of December 31 of the reporting year or the date the emissions caused by the unreasonable delay ends because the infrastructure commenced operation.

(b) For each well-pad or offshore platform at a WEC applicable facility impacted by an unreasonable delay in environmental permitting of gathering or transmission infrastructure, you must calculate the emissions that occurred at the well-pad or offshore platform that were caused by the unreasonable delay according to paragraph (b)(1) or (2) of this section, as applicable.

(1) If the unreasonable delay impacts the entire reporting year, and has resulted in the entire volume of flaring occurring from flare stacks, associated gas flaring, or offshore production flaring, then use the mass CH_4 emissions, in mt CH_4, as reported in § 98.236(m)(8)(iii), (n)(10), and/or (s)(2) of this chapter, as applicable, for the individual flare(s) in the offshore petroleum and natural gas production industry segment and onshore petroleum gas production industry segment used to flare the increased volume of gas from methane emissions mitigation implementation associated with the unreasonable delay in environmental permitting of gathering or transmission infrastructure. If multiple flares are used to flare the increased volume of gas, sum the mass CH_4 emissions for each flare used to flare the increased volume of gas from methane emissions mitigation implementation to determine the cumulative emissions associated with the permitting delay.

(2) If the unreasonable delay impacts only a portion of the reporting year or only a portion of the flaring emissions, determine the eligible emissions as specified in paragraph (b)(2)(i) or (ii) of this section, as applicable.

(i) If you have records to calculate the mass CH_4 emissions from the flare(s) used to flare the increased volume of gas from methane emissions mitigation implementation associated with the unreasonable delay in environmental permitting of gathering or transmission according to the applicable methods in subpart W of this chapter for the specific time period eligible for the exemption, you must calculate the methane emissions for the specific time period eligible for the exemption from each flare used to flare the increased volume of gas from methane emissions mitigation implementation associated with the unreasonable delay. If multiple flares are used to flare the increased volume of gas, sum the mass CH_4 emissions for each flare calculated according to this paragraph to determine the cumulative emissions associated with the permitting delay.

(ii) If you do not have records to calculate the mass CH_4 emissions for the exemption period according to paragraph (b)(2)(i) of this section, then calculate the emissions that occurred at the offshore facility or onshore well-pad caused by the unreasonable delay using Equation C-1 of this section.

$$E_{Delay,CH_4} = E_{MMFlare,CH_4} \times K_f \times X_f \tag{Eq. C-1}$$

Where:

$E_{Delay,CH4}$ = Annual CH_4 emissions associated with delay in permitting in the reporting year, mt CH_4.

$E_{MMFlare,CH4}$ = Annual CH_4 emissions from the flare(s) used to flare increased volume of gas from methane emissions mitigation implementation reported in subpart W of this chapter, mt CH_4.

K_f = Eligible timeframe adjustment factor to the CH_4 emissions flaring emissions for partial year exemption period. If you have records of the volume of gas flared from the impacted flare(s) during the exemption period, use the ratio of the volume of gas flared during the exemption period to the total annual volume of gas flared from the impacted flare(s) to determine K_f; otherwise, use the ratio of hours in the exemption period to the total annual hours in the reporting year (8760 or, for leap years, 8784) to determine K_f.

X_f = Fraction of the flared emissions reported in subpart W of this chapter that occurred from the flare(s) due to the unreasonable delay. This fraction can be estimated based on company records of flare emissions prior to the unreasonable delay or through engineering calculations of flare volumes related to other sources vented to the flare(s).

§ 99.33 What are the recordkeeping requirements for methane emissions caused by an unreasonable delay in environmental permitting of gathering or transmission infrastructure?

(a) For each communication the entity seeking the permit has had with the permitting authority regarding the permit application:

(1) The date and type of communication.

(2) The date of the facility's response to the communication.

(3) Information on whether the facility's response included modification to the permit application.

(b) Records of values used in the calculation of the emissions that occurred at the well-pad caused by the unreasonable delay.

Subpart D—Regulatory Compliance Exemption

§ 99.40 When does the regulatory compliance exemption come into effect, and under what conditions does the exemption cease to be in effect?

(a) The requirements of this subpart only apply to a WEC applicable facility when the total facility applicable emissions for that WEC applicable facility as calculated in accordance with § 99.21(a) exceed 0 mt CH_4.

(b) The requirements of § 99.41 shall only be in effect when each of the following conditions are met:

(1) A determination has been made by the Administrator that methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 of the Act have been approved and are in effect in all States with respect to the applicable facilities; and

(2) A determination has been made by the Administrator that the emissions reductions achieved by compliance with the requirements described in paragraph (b)(1) of this section will result in equivalent or greater emissions reductions on a nationwide basis as would be achieved

by the proposed rule of the Administrator entitled ‘Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review’ (86 FR 63110; November 15, 2021), if such rule had been finalized and implemented.

(c) At such time that the conditions specified in paragraphs (b)(1) and (2) of this section are met, the reporting requirements of § 99.41 shall come into effect beginning with the WEC filing due on the date specified in § 99.5 in the calendar year following the calendar year in which the conditions were met. Imposition of the waste emission charge shall not be made on an applicable facility meeting the requirements for regulatory compliance exemption for methane emissions that occurred during the calendar year during which the conditions are met.

(d) If any of the conditions in paragraph (b)(1) or (2) of this section cease to apply after the Administrator has made the determinations in paragraph (b)(1) and (2) of this section, the reporting requirements of § 99.41 shall cease to be in effect beginning with the WEC filing due on the date specified in § 99.5 in the calendar year during which either of the conditions were no longer met.

§ 99.41 Which facilities qualify for the exemption for regulatory compliance?

(a) The total facility applicable emissions for the WEC applicable facility as calculated in accordance with § 99.21(a) or (d) must exceed 0 mt.

(b) The WEC applicable facility must contain one or more affected facilities or one or more designated facilities.

(c) At the WEC applicable facility, all affected facilities and all designated facilities located at this WEC applicable facility, must have no deviations or violations with the methane emissions requirements of part 60 of this chapter and the methane emissions requirements requirements of an applicable approved state, Tribal, or Federal plan in part 62 of this chapter, including all applicable emission standard, work practice, monitoring, reporting, and recordkeeping requirements.

§ 99.42 What are the reporting requirements for the exemption for regulatory compliance?

(a) A facility eligible for the regulatory compliance exemption that meets the criteria described in § 99.41 shall include information as described in paragraph (b) of this section. A facility that meets the criteria described in § 99.41(a) and (b) but is not eligible for the exemption because it does not meet the criteria in § 99.41(c) shall include information as described in paragraph (d) of this section. The regulatory compliance exemption information shall be submitted as described in § 99.7.

(b) A facility meeting the criteria in § 99.41 must report all of the information specified in paragraphs (b) of this section, as applicable.

(1) For each WEC applicable facility, an assertion that the facility meets all of the eligibility criteria in § 99.41.

(2) The ICIS-AIR ID (or Facility Registry Service (FRS) ID if the ICIS-AIR ID is not available) and EPA Registry ID from CEDRI associated with each affected facility and designated facility located at the WEC applicable facility.

(3) If a report, or reports, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, cover the complete reporting year *(i.e.,* January 1 through December 31, inclusive), then submit as attachment(s) the applicable report(s).

(4) If a report, or reports, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, does not cover the complete reporting year (*i.e.,* January 1 through December 31, inclusive), then submit as attachment(s) the applicable report(s).

(c) If, pursuant to paragraph (b)(4) of this section, you are unable to provide an annual report covering the entire reporting year at the time of the initial submittal specified in § 99.5, you must provide a revised WEC filing on or before such time that an annual report covering the entire reporting year is required to be submitted under the applicable requirements of part 60 of this chapter or an applicable approved state, Tribal, or Federal plan in part 62 of this chapter. This requirement also applies in the case where the initial WEC filing contains an annual report covering only a portion of the reporting year. On or before such time that an annual report is due under the applicable requirements of part 60 of this chapter or an applicable approved state, Tribal, or Federal plan in part 62 of this chapter for the portion of the reporting year for which a previously submitted report does not cover, you must provide a revised WEC filing including the subsequent annual report. The resubmission of the revised WEC filing shall be considered timely under this paragraph if it is made on or before the date that the annual report is due under the applicable requirements of part 60 of this chapter or an applicable approved state, Tribal, or Federal plan in part 62 of this chapter. In such cases where a newly available report indicates one or more deviations or violations from applicable methane emissions requirements that were not previously indicated in the WEC filing for the reporting year (*i.e.*, the WEC applicable facility would no longer qualify for the regulatory compliance exemption), a WEC applicable facility would no longer be subject the reporting requirements in § 99.42(b) and would become subject to the reporting requirements in § 99.42(d) in the revised WEC filing.

(d) If least one of the affected facilities subject to the requirements of part 60 of this chapter or designated facilities subject to the requirements of an applicable approved state, Tribal, or Federal plan in part 62 of this chapter that is contained within your WEC applicable facility has a deviation or violation from its applicable methane emissions requirements (i.e., does not meet the criteria in § 99.41(c)), provide a copy of one report, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, that demonstrates that the affected facility or designated facility were not in compliance.

(e) A WEC applicable facility's eligibility for the regulatory compliance exemption pursuant to this subpart does not constitute a determination of compliance for part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, for any affected facility or designated facility present at the applicable facility.

(f) A WEC applicable facility's eligibility for the regulatory compliance exemption during a given reporting year does not preclude reassessment of applicable waste emissions charges for that applicable facility upon discovery by the Administrator or a delegated authority of any violation of the methane emissions requirements pursuant to part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, for the affected facilities or designated facilities present at the applicable facility.

Subpart E—Exemption for Permanently Shut-in and Plugged Wells

§ 99.50 Which facilities qualify for the exemption of emissions from permanently shut-in and plugged wells?

(a) The total facility applicable emissions for the WEC applicable facility containing permanently shut-in and plugged wells must exceed 0 mt as calculated in accordance with § 99.21(a).

(b) This exemption is applicable to WEC applicable facilities in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment as defined in § 99.2 that permanently shut-in and plugged well(s) during the reporting year. For the purposes of applying this exemption, a permanently shut-in and plugged well is one that has been permanently sealed, following all applicable local, state, or federal regulations in the jurisdiction where the well is located, to prevent any potential future leakage of oil, gas, or formation water into shallow sources of potable water, onto the surface, or into the atmosphere. Site reclamation following placement of a metal plate or cap is not required to be completed for the well to be considered permanently shut-in and plugged for the purposes of this part.

§ 99.51 What are the reporting requirements for the exemption for wells that were permanently shut-in and plugged?

(a) Report the following information for each well at a WEC applicable facility, in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment, that was permanently shut-in and plugged in the reporting year.

(1) Well identification (ID) number as reported in part 98, subpart W of this chapter.

(2) Date the well was permanently shut-in and plugged, which for the purposes of this exemption, is the date when welding or cementing of a metal plate or cap onto the casing end was completed.

(3) The statutory citation for each applicable state, local, and federal regulation stipulating requirements that were applicable to the closure of the permanently shut-in and plugged well.

(4) The equation used to calculate equipment leak emissions attributable to the well (*i.e.*, Equation E-2A or E-2B of this subpart).

(5) The emissions attributable to the well calculated using Equation E-1, E-3, or E-4 of this subpart, as applicable.

(b) The total quantity of methane emissions attributable to all wells that were permanently shut-in and plugged at a WEC applicable facility, in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment, during the reporting year, calculated using Equation E-5 of this subpart.

§ 99.52 How are the net emissions attributable to all wells at a WEC applicable facility that were permanently shut-in and plugged in the reporting year quantified?

(a) For the purposes of this section, the following source types (as specified in part 98, subpart W of this chapter) constitute emissions directly attributable to an offshore petroleum and natural gas production or onshore petroleum and natural gas production well:

(1) Wellhead equipment leaks.

(2) Liquids unloading.

(3) Workovers with hydraulic fracturing.

(4) Workovers without hydraulic fracturing.

(b) Calculate the annual emissions attributable to each well that was permanently shut-in and plugged during the reporting year and included in the submittal pursuant to § 99.51 using Equations E-1, E-3 or E-4 of this section, as applicable.

(1) For onshore petroleum and natural gas production wells that are part of a WEC applicable facility that are permanently shut-in and plugged in reporting years 2025 and later:

(i) Equation E-1 of this section must be used to quantify the methane emissions directly attributable to each permanently shut-in and plugged well.

$$E_{PW,CH_4} = E_{Leaks,CH_4} + E_{LU,CH_4} + E_{WwHF,CH_4} + E_{WwoHF,CH_4} \qquad \text{(Eq. E-1)}$$

Where:

$E_{PW,CH4}$ = The annual quantity of methane emissions directly attributable to an individual well that was permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility, mt CH_4.

$E_{Leaks,CH4}$ = The annual quantity of methane emissions attributable to the well from wellhead equipment leaks as calculated using Equation E-2A or E-2B of this section, as applicable, for the reporting year, mt CH_4.

$E_{LU,CH4}$ = The annual quantity of methane emissions attributable to the well from liquids unloading as reported pursuant to proposed § 98.236(f)(1)(x) or (f)(2)(viii) of this chapter, as applicable, for the reporting year, mt CH_4.

$E_{WwHF,CH4}$ = The quantity of methane emissions attributable to the well from workovers with hydraulic fracturing as reported pursuant to proposed § 98.236(g)(9) of this chapter for the reporting year, mt CH_4.

$E_{WwoHF,CH4}$ = The quantity of methane emissions attributable to the well from workovers without hydraulic fracturing and without flaring as reported pursuant to proposed § 98.236(h)(3)(iv) of this chapter for the reporting year, mt CH_4.

(ii) If equipment leak surveys were used to quantify methane emissions from the permanently shut-in and plugged well and reported pursuant to § 98.236(q) of this chapter in the part 98 report for a WEC applicable facility, Equation E-2A of this section must be used to calculate $E_{Leaks,CH4}$.

$$E_{Leaks,CH_4} = \sum_{p=1}^{N_p}\left(EF_p \times \sum_{z=1}^{x_p} T_{p,z}\right) \times M_{CH_4} \times k \times \rho_{CH_4} \times 10^{-3} \text{(Eq. E-2A)}$$

Where:

$E_{Leaks,CH4}$ = The annual quantity of methane emissions attributable to the well from wellhead equipment leaks as reported pursuant to § 98.236(q) of this chapter for the reporting year, mt CH_4.

p = Component type as specified in proposed § 98.233(q)(2)(iii) of this chapter.

N_p = The number of component types with detected leaks at the well.

EF_p = The leaker emission factor for component "p" as specified in proposed § 98.233(q)(2)(iii) of this chapter, scf whole gas/hour/component.

M_{CH4} = The mole fraction of CH_4 in produced gas for the sub-basin associated with the well, as reported pursuant to proposed § 98.236(aa)(1)(ii)(I), unitless.

x_p = The total number of specific components of type "p" detected as leaking at the permanently shut-in and plugged well in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$T_{p,z}$ = The total time the surveyed component "z" of component type "p" was assumed to be leaking. If one leak detection survey is conducted in the calendar year, assume the component was leaking from the beginning of the reporting year until the date the well was plugged in accordance with § 99.51(a)(2), hours; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the date the well was plugged in accordance with § 99.51(a)(2), hours; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date the well was plugged in accordance with § 99.51(a)(2), hours; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (*i.e.*, not operating under pressure) using an engineering estimate based on best available data.

k = The factor to adjust for undetected leaks by respective leak detection method, where k equals 1.25 for the methods in proposed § 98.234 (a)(1), (3) and (5) of this chapter; k equals 1.55 for the method in proposed § 98.234(a)(2)(i) of this chapter; and k equals 1.27 for the method in proposed § 98.234(a)(2)(ii) of this chapter. Select the factor for the leak detection method used for the permanently shut-in and plugged well, unitless.

ρ_{CH4} = Density of methane, 0.0192 mt/Mscf.

10^{-3} = Conversion factor from scf to Mscf.

(iii) If equipment leaks by population count were used to quantify methane emission from the permanently shut-in and plugged well and reported pursuant to § 98.236(r) of this chapter in the part 98 report for a WEC applicable facility, Equation E-2B of this section must be used to calculate $E_{Leaks,CH4.}$

$$E_{Leaks,CH_4} = EF_{wh} \times M_{CH_4} \times T \times \rho_{CH_4} \times 10^{-3} \qquad \text{(Eq. E-2B)}$$

Where:

$E_{Leaks,CH4}$ = The annual quantity of methane emissions attributable to the well from wellhead equipment leaks as reported pursuant to § 98.236(r) of this chapter for the reporting year, mt CH_4.

EF_{wh} = The population emission factor for wellheads, as listed in proposed Table W-1 of subpart W of part 98 of this chapter, scf whole gas/hour/wellhead.

M_{CH4} = The mole fraction of CH_4 in produced gas for the sub-basin associated with the well as reported pursuant to proposed § 98.236(aa)(1)(ii)(I) of this chapter, unitless.

T = The total time that has elapsed from the beginning of the reporting year until the date the well was plugged in accordance with § 99.51(a)(2), hours.

P_{CH4} = Density of methane, 0.0192 mt/Mscf.

10^{-3} = Conversion factor from scf to Mscf.

(2) For onshore petroleum and natural gas production wells that are part of a WEC applicable facility that are permanently shut-in and plugged in reporting year 2024, Equation E-3 of this section must be used to quantify the methane emissions attributable to the well:

$$E_{PW,CH_4} = (E_{LkQ,CH_4} + E_{LkR,CH_4} + E_{LU,CH_4} + E_{Ww,HF,CH_4} + E_{WwoHF,CH_4}) \times \frac{\left(\frac{Q_{ng,PW}}{6}\right) + Q_{oil,PW} + Q_{cond,PW}}{\left(\frac{Q_{ng,WAF}}{6}\right) + Q_{oil,WAF} + Q_{cond,WAF}} \quad \text{(Eq. E-3)}$$

Where:

$E_{PW,CH4}$ = The annual quantity of methane emissions attributable to an individual well that was permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility, mt CH_4.

E_{LkQ} = The WEC applicable facility total annual quantity of methane emissions from equipment leaks reported pursuant to proposed § 98.236(q)(2)(ix) of this chapter for the reporting year, mt CH_4.

E_{LkR} = The WEC applicable facility total annual quantity of methane emissions from equipment leaks reported pursuant to proposed § 98.236(r)(1)(vi) of this chapter for the reporting year, mt CH_4.

E_{LU} = The WEC applicable facility total annual quantity of methane emissions from liquids unloading as reported pursuant to proposed §§ 98.236(f)(1)(x) and (f)(2)(viii) of this chapter for the reporting year, mt CH_4.

E_{WwHF} = The WEC applicable facility total annual quantity of methane emissions from workovers with hydraulic fracturing as reported pursuant to proposed § 98.236(g)(9) of this chapter for the reporting year, mt CH_4.

E_{WwoHF} = The WEC applicable facility total annual quantity of methane emissions from workovers without hydraulic fracturing as reported pursuant to proposed § 98.236(h)(3)(iv) of this chapter for the reporting year, mt CH_4.

$Q_{ng,PW}$ = The total annual quantity of natural gas that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(iii)(C) of this chapter, in thousand standard cubic feet.

6 = Conversion factor from thousand standard cubic feet of natural gas to barrel of oil equivalent.

$Q_{oil,PW}$ = The total quantity of crude oil that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(iii)(D) of this chapter, in barrels.

$Q_{cond,PW}$ = The total quantity of condensate that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(iii)(E) of this chapter, in barrels.

$Q_{ng,WAF}$ = The total quantity of natural gas that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(i)(B) of this chapter, in thousand standard cubic feet.

$Q_{oil,WAF}$ = The total quantity of crude oil that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(i)(C) of this chapter, in barrels.

$Q_{cond,WAF}$ = The total quantity of condensate that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(i)(D) of this chapter, in barrels.

(3) For offshore petroleum and natural gas production wells that are part of a WEC applicable facility that are permanently shut-in and plugged in any reporting year, Equation E-4 of this section must be used to quantify the methane emissions attributable to the well.

$$E_{PW,CH_4} = (E_{Leaks,CH_4}) \times \frac{\left(\frac{Q_{ng,PW}}{6}\right) + Q_{oil,PW} + Q_{cond,PW}}{\left(\frac{Q_{ng,WAF}}{6}\right) + Q_{oil,WAF} + Q_{cond,WAF}} \quad \text{(Eq. E-4)}$$

Where:

$E_{PW,CH4}$ = The annual quantity of methane emissions attributable to an individual well that was permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility, mt CH_4.

$E_{Leaks,CH4}$ = The WEC applicable facility total annual quantity of methane emissions from non-compressor component level fugitives (*i.e.*, equipment leaks) reported pursuant to proposed § 98.236(s)(3)(ii) of this chapter for the reporting year, mt CH_4.

$Q_{ng,PW}$ = The total annual quantity of natural gas that is produced and sent to sale from the well in the reporting year as reported pursuant to proposed § 98.236(aa)(2)(iv) of this chapter, in thousand scf.

6 = Conversion factor from thousand standard cubic feet of natural gas to barrel of oil equivalent.

$Q_{oil,PW}$ = The total quantity of crude oil that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(v) of this chapter, in barrels.

$Q_{cond,PW}$ = The total quantity of condensate that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(vi) of this chapter, in barrels.

$Q_{ng,WAF}$ = The total quantity of natural gas that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(i) of this chapter, in thousand scf.

$Q_{oil,WAF}$ = The total quantity of crude oil that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(ii) of this chapter, in barrels.

$Q_{cond,WAF}$ = The total quantity of condensate that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(iii) of this chapter, in barrels.

(c) Calculate the total emissions attributable to all wells included in the submittal received pursuant to § 99.51 using Equation E-5 of this section:

$$E_{Plug,CH_4} = \sum_{j=1}^{N} E_{PW,CH_4} \text{(Eq. E-5)}$$

$E_{Plug,CH4}$ = The total quantity of annual methane emissions, as determined in subpart E of this part, at the WEC applicable facility in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments, attributable to all wells that were permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements, mt CH_4.

$E_{PW,CH4}$ = The annual quantity of methane emissions attributable to a well “j” that was permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility calculated using Equation E-1, E-3, or E-4 of this section, as applicable.

N = Total number of wells that were permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility.

[FR Doc. 2024-00938 Filed: 1/25/2024 8:45 am; Publication Date: 1/26/2024]

From: Reiten, John R.
To: Beehler, Jace; Nowatzki, Mike G.
Subject: Fwd: Join Request: Challenge to Clean Air Act Section 111(d) State Implementation Plan Regulations (Joins Due: Tuesday, January 16 at noon (Eastern))
Date: Friday, January 12, 2024 2:28:43 PM
Attachments: image001.png
WV et al Comment on CAA Rule 111(d).pdf
2023-25269.pdf

From: Axt, Philip J. <pjaxt@nd.gov>
Sent: Friday, January 12, 2024 2:27:42 PM
To: Reiten, John R. <jreiten@nd.gov>; Norrell, Ryan <ryan.norrell@nd.gov>
Subject: FW: Join Request: Challenge to Clean Air Act Section 111(d) State Implementation Plan Regulations (Joins Due: Tuesday, January 16 at noon (Eastern))

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

-Phil

From: Axt, Philip J.
Sent: Friday, January 12, 2024 2:20 PM
To: Michael R. Williams <Michael.R.Williams@wvago.gov>
Cc: garry.gaskins@oag.ok.gov; jennifer.lewis@oag.ok.gov; 'Spencer J. Davenport' <Spencer.J.Davenport@wvago.gov>; Carpenter, Katie L. <katcarpenter@nd.gov>
Subject: Join Request: Challenge to Clean Air Act Section 111(d) State Implementation Plan Regulations (Joins Due: Tuesday, January 16 at noon (Eastern))

Hi Michael –

North Dakota is onboard. Appreciate y’all taking this one on.

Please use following sig block (feel free to re-format for consistency):

State of North Dakota
Drew H. Wrigley
Attorney General
By: /s/ Philip Axt
Philip Axt (ND Bar No. 09585)
Solicitor General
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600 E. Boulevard Ave., Dept. 125
Bismarck, ND 58505
Telephone: (701) 328-2210
Counsel for North Dakota

Have a great weekend.

-Phil

Philip Axt
Solicitor General of North Dakota
Office of Attorney General Drew Wrigley
pjaxt@nd.gov | 701-328-3625

From: Michael R. Williams <Michael.R.Williams@wvago.gov>
Sent: Wednesday, January 10, 2024 8:43 PM
To: 'LaCour, Edmund' <Edmund.LaCour@AlabamaAG.gov>; 'Robertson, Katherine' <Katherine.Robertson@AlabamaAG.gov>; Bowdre, Barrett <Barrett.Bowdre@AlabamaAG.gov>; Robert.Tambling@alabamaag.gov; Alloway, Jessie M (LAW <jessie.alloway@alaska.gov>; Mills, Cori M (LAW <cori.mills@alaska.gov>; Dizon, Ninia R (LAW <ninia.dizon@alaska.gov>; nicholas.bronni@arkansasag.gov; Heather Jones <heather.jones@arkansasag.gov>; Amanda Wentz <amanda.wentz@arkansasag.gov>; Dylan Jacobs <dylan.jacobs@arkansasag.gov>; Michael Cantrell <Michael.Cantrell@ArkansasAG.gov>; Henry.Whitaker@myfloridalegal.com; James Percival <James.Percival@myfloridalegal.com>; Kathryn Inman <Kathryn.Inman@myfloridalegal.com>; Daniel Bell <Daniel.Bell@myfloridalegal.com>; Christopher Baum <Christopher.Baum@myfloridalegal.com>; Stephen Petrany <SPetrany@LAW.GA.GOV>; Ross Bergethon <RBergethon@LAW.GA.GOV>; Jordan Watson <JWatson@LAW.GA.GOV>; josh.turner@ag.idaho.gov; isaac.considine@ag.idaho.gov; White, Kimi <Kimi.White@ag.idaho.gov>; Corrine.Youngs@atg.in.gov; Barta, James A <James.Barta@atg.in.gov>; Torres, Lori <Lori.Torres@atg.in.gov>; cory.voight@atg.in.gov; Holmes, Melinda R <melinda.holmes@atg.in.gov>; eric.wessan@ag.iowa.gov; Powell, Anthony J. <anthony.powell@ag.ks.gov>; Daniel.Burrows@ag.ks.gov; 'Burris, Jesse' <Jesse.Burris@ag.ks.gov>; Kambli, Abhishek <Abhishek.Kambli@ag.ks.gov>; Dalton, Charles <Charles.Dalton@ag.ks.gov>; dwight.carswell@ag.ks.gov; Kuhn, Matt F (KYOAG <Matt.Kuhn@ky.gov>; Maddox, Victor (KYOAG <victor.maddox@ky.gov>; blake.christopher@ky.gov; Murrill, Elizabeth <MurrillE@ag.louisiana.gov>; 'St. John, Joseph' <StJohnJ@ag.louisiana.gov>; Short, Tracy <ShortT@ag.louisiana.gov>; McPhee,

Shae <McPheeS@ag.louisiana.gov>; Scott Stewart <Scott.Stewart@ago.ms.gov>; Justin Matheny <Justin.Matheny@ago.ms.gov>; Whitney.Lipscomb@ago.ms.gov; Anthony Shults <Anthony.Shults@ago.ms.gov>; Hart.Martin@ago.ms.gov; Divine, Josh <Josh.Divine@ago.mo.gov>; Johnson, Jeff <Jeff.Johnson@ago.mo.gov>; Corrigan, Christian <Christian.Corrigan@mt.gov>; Derek.Oestreicher@mt.gov; 'Brent Mead' <Brent.Mead2@mt.gov>; Torstensen, Peter <Peter.Torstensen@mt.gov>; Hamilton, Eric <eric.hamilton@nebraska.gov>; 'Lavene, Justin' <justin.lavene@nebraska.gov>; Viglianco, Zachary <Zachary.Viglianco@nebraska.gov>; Titus, Courtney R. <ctitus@nd.gov>; Axt, Philip J. <pjaxt@nd.gov>; Christopher.Bond@doj.nh.gov; Anthony.J.Galdieri@doj.nh.gov; Michael Hendershot <Michael.Hendershot@OhioAGO.gov>; Mathura Sridharan <Mathura.Sridharan@OhioAGO.gov>; Stephen Carney <Stephen.Carney@OhioAGO.gov>; amicus@ohioago.gov; Zach West <zach.west@oag.ok.gov>; garry.gaskins@oag.ok.gov; 'Emory Smith' <esmith@scag.gov>; Thomas Hydrick <ThomasHydrick@scag.gov>; Joseph Spate <josephspate@scag.gov>; Paul.Swedlund@state.sd.us; Brandon J. Smith <Brandon.Smith@ag.tn.gov>; Andree S. Blumstein <Andree.Blumstein@ag.tn.gov>; Matt Rice <Matt.Rice@ag.tn.gov>; 'Gabriel Krimm' <Gabriel.Krimm@ag.tn.gov>; Whitney Hermandorfer <Whitney.Hermandorfer@ag.tn.gov>; Brent Webster <Brent.Webster@oag.texas.gov>; Aaron Nielson <Aaron.Nielson@oag.texas.gov>; Ralph.molina@oag.texas.gov; Grant Dorfman <Grant.Dorfman@oag.texas.gov>; Lanora Pettit <Lanora.Pettit@oag.texas.gov>; James Lloyd <James.Lloyd@oag.texas.gov>; Judd Stone <Judd.Stone@oag.texas.gov>; Joe Mazzara <Joe.Mazzara@oag.texas.gov>; Melissa Holyoak <melissaholyoak@agutah.gov>; chrisbates@agutah.gov; rcantrell@agutah.gov; aferguson@oag.state.va.us; kkilgore@oag.state.va.us; Croslow, Lucas W.E. <LCroslow@oag.state.va.us>; Gallagher, Kevin M. <KGallagher@oag.state.va.us>; ryan.schelhaas@wyo.gov; ag.amicus@wyo.gov
Cc: garry.gaskins@oag.ok.gov; Jennifer Lewis <jennifer.lewis@oag.ok.gov>; Spencer J. Davenport <Spencer.J.Davenport@wvago.gov>
Subject: Join Request: Challenge to Clean Air Act Section 111(d) State Implementation Plan Regulations (Joins Due: Tuesday, January 16 at noon (Eastern))

All,

Oklahoma and West Virginia invite you to join our challenge to a final rule that EPA recently promulgated changing the procedures under which States submit state implementation plans as mandated by Section 111(d) of the Clean Air Act. To meet a statutory deadline, we're asking for joins no later than **Tuesday, January 16, at noon Eastern**.

The issue sounds like a mouthful, but it's actually rather straightforward. Under Section 111(d), States must submit plans to EPA that provide for the establishment, implementation, and enforcement of standards of performance for existing emission sources, like power plants. A recently finalized rule (attached) gives States much less discretion in figuring out how these existing sources can comply. It also gives States significantly less time to comply. The comment and the attached circulation from last year lay that out in further detail.

West Virginia led comments on the proposed rule (also attached), which many of you joined. We expect our challenge will raise many of the same issues. Among other things, the rule's attempt to unduly narrow state discretion is inconsistent with the statute's express provisions. The rule also creates a state plan call process that the statute doesn't contemplate, either. And the timing provisions are arbitrary and inappropriate. We'll be making these arguments before the D.C. Circuit, as the CAA requires challenges like these to be made there.

Industry is very concerned about this rule. We've heard from some of them directly, and I understand some of you all have, too. That said, the States are in the best position to challenge the rule because it directly regulates us. So we see substantial reason to jump in. (For those involved in challenging the recent ozone SIP/FIP determinations, this process of squeezing the State on the front end to grease the skids for EPA to act on the back end should feel familiar.) The rule is also directly tied to the recently promulgated EPA methane rules and anticipated "Clean Power Plan 2.0" greenhouse gas rules.

If you'd like to join, **please email me with your join and a signature block for the petition for review**. We'll plan to circulate a draft petition for review over the next couple days. (As you know, that filing is a non-substantive, one-page document.)

As always, just reach out if you have any questions or concerns. And thank you for considering it.

Michael

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Michael S. Regan
Administrator, Environmental Protection Agency
1200 Pennsylvania Ave NW, Suite 1101A
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Submitted Electronically via Regulations.gov

Re: Comments on the Proposed Rulemaking Titled "Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)" by the Attorneys General of the State of West Virginia, Alabama, Alaska, Arkansas, Georgia, Idaho, Indiana, Iowa, Kentucky, Louisiana, Mississippi, Missouri, Montana, Nebraska, North Dakota, Ohio, Oklahoma, South Carolina, Texas, Utah, Virginia, and Wyoming (Docket No. EPA-HQ-OAR-2021-0527)

Dear Administrator Regan:

The undersigned States appreciate the opportunity to comment on EPA's proposed revisions to the implementation regulations for state plans under Section 111(d) of the Clean Air Act. *See* 87 Fed. Reg. 79,176 (Dec. 23, 2022) ("Proposed Rule"). We are strongly committed to responsible and efficient state regulation as part of the CAA's cooperative-federalism framework. We also understand the agency's duty to respond to the D.C. Circuit's decision concerning EPA's last rule in this area. But we have four areas of concern with the Proposed Rule that we urge the agency to consider further.

First, like EPA's recent supplemental proposal on methane emissions, the Proposed Rule suggests timelines inadequate for States to effectively develop and submit their plans to EPA. *See* "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 87 Fed. Reg. 74,702 (Dec. 6, 2022) ("Supplemental Proposal"). *Second*, the Proposed Rule assumes a new power to issue state plan calls that the text of Section 111(d) does not support. *Third*, the Proposed Rule encroaches on local-level discretion—on the one hand, adding onerous requirements the statute does not contemplate for States wishing to exercise their congressionally conferred discretion over source-specific factors, and on the other, dictating new extra-statutory factors that EPA wishes the States would take into account. *Fourth*, the Proposed Rule's limited promise of compliance flexibility could be an impermissible step towards the sort of outside-the-fenceline measures that Section 111(d) does *not* permit EPA to use as the basis for emission guidelines.

We respectfully urge EPA to reconsider the Proposed Rule and restore needed time and state discretion to the important process of developing Section 111(d) implementation plans.

BACKGROUND

Section 111 of the Clean Air Act creates a partnership between EPA and the States for establishing emission standards for stationary sources of air pollution. 42 U.S.C. § 7411. The CAA assigns EPA the main regulatory role in specifying standards for new and modified sources, but Section 111(d) adopts a cooperative-federalism approach for existing sources. Specifically, it requires EPA to "establish a procedure similar to that provided by [Section 110]" for States to submit plans that "establish[] standards of performance" for covered existing sources in their borders. *Id.* § 7411(d)(1). The standards of performance the States set, in turn, must "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction" that EPA "determines has been adequately demonstrated." *Id.* § 7411(a)(1). So while EPA promulgates emission guidelines based on its assessment of adequately demonstrated technology for source categories, it is up to the States to set requirements for specific sources and submit those plans to EPA under the process the agency sets out.

EPA respected this cooperative-federalism approach for several decades until it enacted the ultimately ill-fated Clean Power Plan rule. 80 Fed. Reg. 64,662 (Oct. 23, 2015). As the Supreme Court confirmed last Term, Congress did not give the agency power under Section 111(d) to effectively force a sector-wide shift in electricity production. *See West Virginia v. EPA*, 142 S. Ct. 2587, 2593 (2022).

In 2019, the agency tried a course correction when it replaced the Clean Power Plan rule with the Affordable Clean Energy rule ("ACE"). 84 Fed. Reg. 32,520 (July 8, 2019). Though the majority of litigation over that rule focused on EPA's emission-guideline-setting authority, part of the lower-court proceedings concerned the ACE rule's implementing regulations for Section 111(d). *Id.* at 32,575-84. That aspect of the rule gave States 36 months to develop and submit their plans for emission reduction and two years to demonstrate compliance progress. *See* 40 C.F.R. §§ 60.23a(a)(1), 60.27a(c). This homeostasis was short-lived, however, as the D.C. Circuit vacated the provisions relating to these timelines and other implementation details. *Am. Lung Ass'n v. EPA*, 985 F.3d 914 (D.C. Cir. 2021) ("*ALA*"). The court reasoned that EPA failed to meaningfully address why shorter deadlines were unworkable. *Id.* at 992. It also concluded that, despite EPA's statutory duty to use "similar" procedures under Sections 110 and 111(d), EPA could not graft Section 110 deadlines onto Section 111 without comparing the relative scale of effort in developing and evaluating plans under those sections. *Id.* at 992-93.

The Proposed Rule revisits Section 111(d)'s implementing regulations in response to the D.C. Circuit's decision. But once more, EPA does not meaningfully address why it chose the now *much* shorter deadlines for state plans. Nor does it appropriately reconcile them with other deadlines in the same statute. Additionally, EPA suggests "clarifying" requirements for States' consideration of certain discretionary factors, but the proposal sharply circumscribes the discretion Congress entrusted to the States and replaces it with extra-statutory factors of EPA's choosing.

DISCUSSION

The Proposed Rule does not respect the time States need to develop responsible, complex plans under Section 111(d), nor honor the discretion this portion of the CAA gives the States as EPA's regulatory partners. Though Section 111(d) requires EPA to "prescribe regulations … similar" to Section 110, EPA treats "similar" less as a default in favor of applying the same standards and more as a guideline that adjusts significantly depending on the provision. When dispensing with Section 110's 36-month timeline in favor of a new 15-month one, for instance, the Proposed Rule adjusts the dial too far with too cursory of an explanation. But elsewhere, when it seeks to implement regulatory mechanisms it has never before applied to Section 111(d), EPA adjusts the dial too far the other direction by importing those aspects of Section 110—again, without adequately justifying the change.

And this incongruence with Section 110 isn't the Proposed Rule's only problem lining up with the statutory text. It also effectively sidelines the States. States won't be able to meet the deadlines, especially now that EPA proposes saddling them with new and costly requirements simply for using their discretion—set out in the statute—to apply standards to a specific facility that deviate from EPA's category-wide assessments. And while claiming that parts of the Proposed Rule provide more flexibility to the States, we are concerned that EPA is improperly expanding its power to reject States' plans that don't conform to the agency's policy preferences.

I. States Will Be Unable To Meet EPA's Proposed Timelines.

Most of the Proposed Rule focuses on shortening the timeframe for submitting and enforcing state implementation plans after the D.C. Circuit vacated EPA's prior 36-month submission rule. 87 Fed. Reg. at 79,181-92. But EPA has overcorrected—its proposed 15-month timeline, *id.* at 79,182, does not provide enough room for States to develop appropriate plans.

The stark difference between the 36 months that States have to submit plans under Section 110 and the 15 months that EPA proposes here is the giveaway that something is amiss. Section 111(d) directs EPA to "prescribe regulations which shall establish a procedure similar to" the State-submission procedure set out in Section 110. 42 U.S.C. § 7411(d). EPA acknowledges that the "[proposed Section 111(d)] deadlines are not identical to those for SIPs under CAA section 110," and reasons that "similar" does not mean "identical." 87 Fed. Reg. at 79,182. But that acknowledgment is not an explanation why EPA thinks this approach is needed, much less how so significant a change stays faithful to the statutory text. Two procedures can hardly be called "similar" when one rushes a complex process through in less than half the time of the other. *See, e.g., Duckworth v. Allianz Life Ins. Co. of N. Am.*, 706 F.3d 1338, 1343 (11th Cir. 2013) (providing various definitions of "similar" that reflect a close and corresponding identity between two things).

Yes, the D.C. Circuit struck down the ACE rule because EPA failed to adequately explore the differences between Sections 110 and 111(d) plans and why they might justify different timelines. *ALA*, 985 F.3d at 994-96. But that doesn't mean EPA gets to start from a blank slate when it comes to how much time is enough: Section 111(d) still requires "similar[ity]" to Section 110's process, and the *statute* sets 36 months as the default. 42 U.S.C. §§ 7410(a)(1), 7411(d). Yet EPA seems to take *ALA* as an instruction to decouple the statutes entirely—and misses even *ALA*'s key point on this issue. Any timeline that EPA chooses needs to balance the harms to the public from exposure to pollutants while allowing States sufficient time to develop appropriately complex plans. *ALA*, 985 F.3d at 994-96. The Proposed Rule does not parse the differences in these statutory schemes beyond a few normative descriptions.

Walking through the Proposed Rule's analysis, EPA apparently settled on 15 months by rough comparisons to other sections of the CAA and its implementing regulations. Jumping right to other parts of the statute instead of starting with Section 110's three-year baseline is questionable as a matter of statutory interpretation. EPA should specifically explain why it is justified in setting a "shorter period." 42 U.S.C. § 7410(a)(1). In other words, Congress intentionally started with a longer period, recognizing the complexity of the task that States must undertake, so EPA must at least explain why Congress's reasoned judgment should supposedly be set aside here. *See, e.g.*, *New York v. EPA*, 964 F.3d 1214, 1228 (D.C. Cir. 2020) (Griffith, J., concurring) (noting that Section 110 "affords three years for states to craft implementation plans" and contrasting this timeframe with "divergent timelines" found in other parts of the CAA).

We have concerns with some of the conclusions EPA draws from those other parts of the statute, too.

EPA starts first with Subpart B, which gives States a nine-month timeframe to submit plans after publication of a final emission guideline. We have no quarrel with the rationale that this period would not be enough for most States to submit Section 111(d) plans: EPA correctly notes that most States either failed to submit plans or were substantially late in submitting them on that schedule. 87 Fed. Reg. at 79,183. So too for EPA's Section 129 discussion. *Id.* EPA justifies relying on Section 129 because it references Section 111(d) "in many instances, creating considerable overlap in the functionality of the programs." *Id.* EPA also fairly recognizes that Section 129's 12-month timeline is inappropriate because Section 111(d) "permits states to take into account remaining useful life and other factors," which "could involve more complicated analyses." *Id.* But beyond that, we also observe that the narrower scope of Section 129—governing only waste-incineration units—means those implementation plans should be generally simpler and easier to develop than the broader plans that will be required under Section 111(d). All together, these factors suggest that the implementation deadlines under Section 111(d) should be substantially longer than the deadlines under Subpart B.

The real problems start, though, when EPA considers Section 189 and its 18-month timeframe—the Proposed Rule subjectively judges that Section 189 plan requirements are more complex than those required under Section 111(d). 87 Fed. Reg. at 79,183. So the Proposed Rule treats its 15-month solution as a Goldilocks-like approach: 9 and 12 months are too short, 18 months is too long, so 15 months is just right. But this is not a "just right" situation.

For one thing, we do not agree that Section 189 plans are necessarily more complex than Section 111(d) plans. The latter requires States to make allowances for remaining useful life and other factors that the former does not. Even if we were to agree with EPA's premise that these factors are to be *applied* in only "limited" circumstances (and we do not), States are still required to conduct initial assessments to determine when, exactly, those "limited" circumstances might arise. *Id.* And beyond conclusory statements, EPA has not explained why it thinks Section 189 plans are so uniquely complex that other plans can be assumed to require less time.

For another thing, as we noted before, EPA's strategy takes the time that Congress set as the default (36 months) out of its balancing altogether. This approach is particularly concerning because, according to EPA's report of its own experience, the States regularly need closer to three years than 15 months to promulgate sufficient Section 111(d) plans. 84 Fed. Reg. at 32,568. And even assuming that EPA is right to move *somewhat* below three years, giving *under half* that time goes too far in light of the complexity of the States' task, which will only get harder with the additional information EPA plans to require under the new rule.

EPA also fails to consider the significant compliance issues facing the States. Notably, EPA cuts away the States' compliance period even though it does not propose shortening its *own* evaluation time, which suggests that nothing has changed about the complexity of these plans and the time needed to assess them. The fact that CAA emission regulations have been in limbo for quite a while also supports giving States more time, not less, to adapt to the new legal environment. The Proposed Rule acknowledges that there may be significant variability in how States set implementation plans, but then breezily concludes, "15 months should adequately accommodate the differences in state processes necessary for the development of a state plan that meets applicable requirements." 87 Fed. Reg. at 79,183. The Proposed Rule does not explain how EPA reconciled the state variability it acknowledged with the much shorter and nationally applicable timeline it chose. The Proposed Rule also does not acknowledge that EPA is employing its regulatory authority under Section 111(d) on multiple fronts as of late—see the recent efforts on methane—which will expand the number of sources covered and state plans needed. The States will thus likely need to develop multiple complex plans at the same time. This calls for more time, too. And EPA does not appear to have considered State-specific processes—beyond a brief footnote acknowledgement—that require significantly more time than EPA has provided here. For instance, the West Virginia Legislature must approve legislative rules, and it meets only for a few weeks each year. Meeting a fifteen-month timeframe would be next to impossible if the clock begins ticking a few months before an annual legislative session: There would not be enough time to rush a plan before it begins, and 15 months would expire before the next one. And West Virginia is not alone. Texas's legislature, for example, meets for six months every *other* year.

Nor does EPA consider how additional sections in the Proposed Rule render its proposed timeline even more divorced from reality. As explained more below, the Proposed Rule encourages States to set compliance goals and use sources outside the fenceline. 87 Fed. Reg. at 79,207. Setting aside any other concerns with that portion of the Proposed Rule, that undertaking will take more time because it requires the States to consider several additional avenues of emission reduction beyond traditional inside-the-fenceline measures. Also as discussed more below, the Proposed Rule would require extensive justification before States can take remaining useful life and other factors into account in their plans. This, of course, means additional work, too, and in less than half the time from EPA's last rule. EPA notes that the Proposed Rule limits the temporal reach of remaining useful life and other factors, which in its view supports a shorter timeframe for Section 111(d) plans. *Id.* at 79,183. But relying on time saved from improperly pruning the States' statutory discretion, *see infra* Part III, only turns one error into two.

Throughout the Proposed Rule, EPA also makes plan approval contingent on States' "meaningful engagement" with pertinent stakeholders—those most affected by and vulnerable to pollution's health or environmental effects. 87 Fed. Reg. at 79,203. In the first place, the statute does not set this task before the States or give EPA power to reject a plan if States choose not to take it up. EPA claims its authority is derived from both CAA Sections 111(d) and 301(a)(1), *id.* at 79,191, but we do not see in either of those sections support for the idea that EPA can dictate States' day-to-day administrative processes in this way. Even putting that concern to the side, if EPA will compel engagement with affected stakeholders, then it should allow more time—not less—to do so. And if engagement is needed, then the agency should not arbitrarily limit it to those stakeholders EPA thinks count the most. True engagement would also reach those who are affected economically by new restrictions and plan requirements. *See* State Plans for the Control of Certain Pollutants From Existing Facilities, 40 Fed. Reg. 53,340, 53,343 (Nov. 17, 1975) ("States will also have authority to grant variances in cases of economic hardship."). So even assuming EPA can implement these new requirements, the Proposed Rule does not explain how it can pile them on while shortening the timeline for completing them.

Lastly, a fair timeframe to account for all the relevant factors gives space for cooperation between the States and EPA to hash out disagreements or specific policies collaboratively, in the spirit of the CAA. This point proves crucial. We are deeply concerned that shortened timeframes may be an unlawful effort on EPA's part to seize more control over Section 111(d) implementation. According to EPA, even when a State submits a timely proposed implementation plan, the agency will treat the State as having submitted no plan at all if EPA later determines that the plan is incomplete. 87 Fed. Reg. at 79,185. And if by that point the initial 15-month period has run, EPA will assume immediate "authority to provide a Federal plan," *id*, even before the agency has made a formal finding of failure to submit, *id.* at 79,190. So in this scenario, even though the State has acted in good faith to comply with its Section 111(d) obligations, EPA will nevertheless afford that State no opportunity to correct the perceived deficiencies before invoking the statute's federal failsafe. *Id.* Shortened timeframes make this scenario far more likely. So given that EPA will give itself two months to make a completeness determination, *id.* at 79,182, the only way a State could try to assure itself an opportunity to supplement a plan EPA deems incomplete is to submit it at least two months before the already truncated 15-month deadline. And "at least" is doing considerable work: Even that rush on the State's part is no guarantee if EPA refuses to allow additional time to correct any perceived deficiencies, as the Proposed Rule seems to suggest. *Id.* at 79,185. This process hardly reflects the State-centric approach that Congress intended under Section 111(d). *See* 40 Fed. Reg. at 53,343 (explaining that "States will have primary responsibility for developing and enforcing control plans under section 111(d)").

II. EPA Has No Authority To Issue State Plan Calls Under Section 111(d).

We also urge EPA to reconsider its proposal to implement a state-plan-call process similar to that set out in Section 110(k)(5). EPA intends to provide that a failure to submit a revised plan in response to such a call constitutes a failure to submit a plan under Section 111(d)(2). 87 Fed. Reg. at 79,194-95. EPA has no authority to create such a process.

EPA apparently believes that Section 111(d) lets it import the substantive plan-revision requirements from Section 110(k) into its Section 111 regulations. In other words, despite dismissing Section 110(a)'s relevance to appropriate timelines, EPA strictly hews to other parts of Section 110 to justify adopting new state plan calls and other regulatory mechanisms in the Proposed Rule. But Section 111(d) does not support that approach. It directs EPA to "prescribe regulations under which States shall establish a *procedure* similar to that provided by section 7410 of this title under which each State shall *submit* to the Administrator a plan." 42 U.S.C. § 7411(d)(1) (emphases added). Regulations about how States submit their plans to EPA are materially different from regulations about how EPA may judge that plan potentially years later. *See* 87 Fed. Reg. at 79,195 (describing changed "legal or technical conditions" and inadequate "implementation" as justifications for a state plan call, both of which could arise long after EPA approves an initial plan). So while EPA must look to Section 110's *state submission* procedures—found in subsection (a)—it does not have authority to co-opt Section 110's "state plan call" provisions from subsection (k). Subsection (k) is a separate provision addressed to EPA's duties, not the State's.

Section 111(d)(2) further confirms this reading because it sets out Section-specific enforcement powers for EPA: It empowers EPA to act when a State "fails to submit a satisfactory plan" or "fails to enforce" plan provisions. 42 U.S.C. § 7411(d)(2)(A)-(B). This same provision references Section 110(c), but not all of Section 110. *Id.* It does not mention Section 110(k) at all, which sets out *different* enforcement and "error correction" powers relevant to Section 110. So EPA's enforcement power is limited to what Congress gave it in Section 111(d). It cannot claim power to assume federal oversight when a State successfully submits one satisfactory plan but then fails to submit a *second* satisfactory plan at EPA's later insistence. Given the lack of legal authority (and the lack of clear standards for when this power would be invoked), these provisions should also be removed from the Proposed Rule.

III. The Proposed Rule Invades States' Statutorily Guaranteed Discretion.

Similar to EPA's related proposals in other CAA contexts, the Proposed Rule also improperly tries to "push States into abandoning their local-level discretion" by erecting significant roadblocks for any States that seek to exercise it. *See* State of W. Va., et al., Comment Letter on Supplemental Notice of Proposed Rule Establishing New Standards of Performance for New and Modified Sources of Methane In the Oil and Natural Gas Sector 6 (Feb. 13, 2023), http://bit.ly/3XK1kb8.

In Section 111(d), Congress expressly reserved States' right to depart from EPA guidelines for particular existing sources based on their assessment of, "among other factors, the remaining useful life of the existing source." 42 U.S.C. § 7411(d). EPA traditionally interpreted this prerogative to apply in three scenarios: (1) when the cost from plant age, location, or process design is unreasonable; (2) when there is a "physical impossibility of installing [the] necessary control equipment"; and (3) when other factors make a less stringent standard "significantly more reasonable." 87 Fed. Reg. at 79,196.

The Proposed Rule says that it seeks to "clarify" this portion of Section 111(d). 87 Fed. Reg. at 79,199. But when EPA says "clarify," it actually means "restrict." *Id.* EPA wants to revise the third criterion so that it will not approve a State's decision to hold a facility to a standard less stringent than EPA prefers unless the State demonstrates the source's circumstances are "fundamentally different from the information [EPA] considered in the determination of the [best system of emission reduction]." *Id.* States striving to meet this degree of stringency will be saddled with new and unjustified obligations. The Proposed Rule requires States to detail contingencies, restrictive cost considerations, and impacted-communities analyses simply to invoke their statutory ability to factor remaining useful life and other source-specific considerations into their plans. *Id.* at 79,200-01. It is difficult to understand this new requirement other than an attempt to narrow the "range of permissible choices to the States" and to shoehorn States into complying with EPA's category-wide choices for almost every individual source. *Wis. Dep't of Health & Fam. Servs. v. Blumer*, 534 U.S. 473, 495 (2002).

We see no basis in the statute for EPA to restrict the States' congressionally conferred authority in this way. The agency proposes requiring States to go through a new and specific form of analysis that is nowhere to be found in the CAA, 87 Fed. Reg. at 79,200-01, and without accounting for the new costs these requirements will add for States that seek to depart from category-wide standards—as the statute contemplates they may. Worse still, EPA intends to *entirely foreclose* States from considering factors like remaining useful life when a plant's retirement date falls outside a prescribed range. *Id.* at 79,201. The CAA puts no bright-line limits like these on the States' discretion. And though we acknowledge that States must exercise reasonable judgment in this analysis, their judgment is not unreasonable merely because they consider source-specific factors different than EPA might.

Notably, EPA justifies its approach as a way to "fix" the current scheme, which it complains could lead to two States considering "two identically situated designated facilities and apply[ing] completely different standards of performance." 87 Fed. Reg. at 79,197. But that hypothetical difference is a quarrel with the statute. Congress invited this State-by-State variation, recognizing that States may view the collective effects of cost, structure, or other source-specific factors differently. These different views may derive, for instance, from the different composition of a particular State's energy portfolio—and may lead to equally good air quality across the board. In any event, EPA cannot justify a move toward a uniform-standard approach Congress did *not* put down in the Code based on perceived problems flowing from the cooperative-federalism regime that it *did*.

Lastly, EPA proposes to transform a provision giving States discretion to consider various factors into one that empowers the agency to require States to consider factors of EPA's own choosing. *See* 87 Fed. Reg. at 79,203 ("EPA interprets this [statutory provision] as providing discretion for the EPA to identify the appropriate factors and conditions under which the circumstance may be reasonably invoked in establishing a [less stringent] standard …."). This reads Section 111(d) backwards. The provision requires EPA to make space for the *States'* discretion ("the Administrator … shall permit the State … to take into consideration"), and contemplates that the States will decide what factors may be relevant ("among other factors"). 42 U.S.C. § 7411(d). This State-focused language gives EPA no power to force States to consider "other factors" EPA deems relevant, like "health and environmental impacts." 87 Fed. Reg. at 79,203. And even if it did, EPA would still at least need to explain why it elevated these considerations above all others, such as the economic effects on surrounding communities.

Section 111(d)'s focus on remaining useful life and other source-specific factors protects the States' role in setting standards for the existing sources in their borders. It does not greenlight an EPA-created checklist for the States to show their work or to do other work at EPA's behest.

IV. EPA Promises States Flexibility But Looks To Be Trying To Back-Door Power For Itself.

Finally, we do not object to the limited areas where the Proposed Rule promises States additional compliance flexibility. But we are concerned that this flexibility arises *only* in the context of allowing trading or averaging to meet performance standards in the aggregate. *See* 87 Fed. Reg. at 79,208 (explaining that EPA will approve state plans that use trading or averaging because "[s]uch flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes"). This portion of the Proposed Rule involves the same measures that the Supreme Court made clear last Term that EPA could not designate directly as a best system of emission reduction. We urge the agency not to use this lone concession to state discretion as an indirect way to reach a similar end.

With how many other provisions in the Proposed Rule cut against state discretion, the agency's ready welcome for state creativity when it comes to trading-based state plans caught our eye. We are concerned that the agency may be laying an inappropriate groundwork for "encouraging" States to adopt measures EPA cannot require outright. For one thing, the Proposed Rule states that while EPA is not addressing the type of "system" the statute allows in this rulemaking, it "may address further those limits … in future emission guidelines." 87 Fed. Reg. at 79,208. Yet the Supreme Court invalidated the agency's prior generation-shifting approach, explaining that the term "system" does not provide the "clear congressional authorization" needed to support EPA guidelines "of such magnitude and consequence." *West Virginia*, 142 S. Ct. at 2614-16. While we trust that EPA will abide by the Supreme Court's direction, this language suggests to us that the agency may still be eager to push those limits.

So we also caution against letting any state discretion to implement trading programs as a compliance mechanism become an additional checkpoint when EPA approves state plans. Whatever options States have under Section 111 to consider state-wide averaging, EPA cannot require States to adopt them. The statute would not let EPA require a State to consider these measures, for instance, or to ask why a State did *not* pursue a trading-based route if it submits a traditional technology-and-processes-based plan instead. Whether a State *could have* adopted trading would also be an inappropriate basis for rejecting a State's decision to set a particular performance standard for a given source. Put directly, if a State explains why remaining useful life and similar considerations support deviating from EPA's category-wide guidelines, EPA could not set aside that judgment because it believes the State should have required trading or similar measures to make up the difference.

In the end, the Proposed Rule is about implementation processes for States to submit plans under Section 111(d). These procedural tools cannot allow EPA to backdoor different or more stringent standards in accordance with its policy preferences. *See Texas v. EPA*, 829 F.3d 405, 411 (5th Cir. 2016) ("The statute mandates that the EPA administrator *shall* approve such a state implementation plan as a whole if it meets all the applicable requirements of this chapter" (cleaned up) (emphasis in original)). Especially given that this issue arises in the same context where the Supreme Court has spoken to EPA's limits, we will be watching if the agency takes what the Proposed Rule packages as increased state discretion and uses it to limit the States' actual range of options at the plan-approval stage.

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We urge EPA to reevaluate the Proposed Rule along these lines and to finalize implementation guidelines that provide adequate time for developing state plans, that stay within Section 111(d)'s bounds, and that respect—not cabin—the discretion Congress safeguarded for the States in this important context. We appreciate the opportunity to provide comments in this rulemaking and are happy to discuss further with the agency as helpful.

Sincerely,

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2021–0527; FRL–8606–01–OAR]

RIN 2060–AV48

Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing amendments to the regulations that govern the processes and timelines for state and Federal plans to implement emission guidelines under Clean Air Act (CAA) New Source Performance Standards for existing sources (the ''implementing regulations''). The amendments include revisions to the timing requirements for state and the EPA actions related to plans; the addition of mechanisms to improve flexibility and efficiency in plan processes; and new requirements for demonstration of timely meaningful engagement with pertinent stakeholders—including, but not limited to, industry, small businesses, and communities most affected by and vulnerable to the impacts of the plan. This action additionally provides a process for states' consideration of 'remaining useful life and other factors' (RULOF) in applying a standard of performance; amends the definition of standard of performance in the implementing regulations; and clarifies compliance flexibilities that states may choose to incorporate into state plans, including trading or averaging. Finally, this action adds requirements for the electronic submission of state plans and provides several other clarifications and minor revisions to the implementing regulations.

DATES: This final rule is effective on December 18, 2023.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2021–0527. All documents in the docket are listed on the *https://www.regulations.gov/* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov/.*

FOR FURTHER INFORMATION CONTACT: For questions about this action contact Dr. Michelle Bergin, Sector Policies and Programs Division (Mail Code D205–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–2726; email address: *bergin.michelle@epa.gov.*

SUPPLEMENTARY INFORMATION: *Preamble acronyms and abbreviations.* We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACE	Affordable Clean Energy Rule
ALA	American Lung Association
BSER	Best System of Emission Reduction
CAA	Clean Air Act
CBI	confidential business information
CDX	Central Data Exchange
CFR	Code of Federal Regulations
EG	Emission Guideline
EGU	electric generating unit
EJ	environmental justice
EPA	Environmental Protection Agency
FIP	Federal Implementation Plan
ICR	Information Collection Request
IoP	Increments of Progress
NAAQS	National Ambient Air Quality Standards
OAQPS	Office of Air Quality Planning and Standards
OMB	Office of Management and Budget
PRA	Paperwork Reduction Act
$PM_{2.5}$	fine particulate matter (2.5 microns and less)
RTC	Response to Comments document
RFA	Regulatory Flexibility Act
RIN	Regulatory Information Number
RULOF	remaining useful life and other factors
SIP	State Implementation Plan
SpeCS	State Planning Electronic Collaboration System
TAR	Tribal Authority Rule
TAS	Treatment as a State
TIP	Tribal Implementation Plan
UMRA	Unfunded Mandates Reform Act
U.S.C.	United States Code

Organization of this document. The information in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

This action applies for the development and adoption of plans for implementation of CAA section 111(d) final emission guidelines (EGs) published in the **Federal Register** after July 8, 2019. In particular, this action applies to states in the development and submittal of state plans and to the EPA in processing state plan submissions and to the EPA in promulgating Federal plans. After the EPA promulgates a final EG, each state that has one or more designated facilities must develop, adopt, and submit to the EPA a state plan under CAA section 111(d). The term ''designated facility'' means ''any existing facility . . . which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility [*i.e.,* a new source].'' *See* 40 CFR 60.21a(b). If a state fails to submit a plan or if the EPA determines that a state plan is not satisfactory, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities located in the state.

Under the Tribal Authority Rule (TAR), eligible tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state (treatment as a state; TAS) for purposes of developing a Tribal Implementation Plan (TIP) implementing an EG. If a tribe obtains approval and submits a TIP, the EPA will use similar timelines and criteria and will follow similar procedures as those for state plans. Tribes that choose to develop plans will have the same flexibilities available to states in this process. The TAR authorizes tribes to develop and implement one or more of its own air quality programs, or portions thereof, under the CAA; however, it does not require tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. A tribe with an approved TAS under TAR for CAA 111(d) is not required to resubmit TAS approval to implement an EG subject to subpart Ba.[1] If a tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *https://www.epa.gov/stationary-sources-air-pollution/adoption-and-submittal-state-plans-designated-facilities-40-cfr.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rule, a memorandum showing the rule edits finalized in this action, and key supporting documents at this same website.

C. Judicial Review and Administrative Review

Section 307(b)(1) of the CAA governs judicial review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the D.C. Circuit: (i) when the agency action consists of ‘‘nationally applicable regulations promulgated, or final actions taken, by the Administrator,’’ or (ii) when such action is locally or regionally applicable, but ‘‘such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.’’ For locally or regionally applicable final actions, the CAA reserves to the EPA complete discretion whether to invoke the exception in (ii) described in the preceding sentence.[2]

This action is ‘‘nationally applicable’’ within the meaning of CAA section 307(b)(1). The final rule governs the EPA's promulgation of emission guidelines under CAA section 111(d), which are nationally applicable regulations for which judicial review is available only in the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) pursuant to CAA section 307(b)(1).[3] Moreover, it revises the generally applicable, nationally consistent implementing regulations that govern the development and submission for all states of state plans and the EPA's development of Federal plans pursuant to EGs under CAA section 111(d), as well as the EPA's review of states' plans.

In the alternative, to the extent a court finds this final action to be locally or regionally applicable, the Administrator is exercising the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of ‘‘nationwide scope or effect’’ within the meaning of CAA section 307(b)(1).[4] As explained above, this final action is revising a single set of nationally consistent implementing regulations that apply to every state that must develop a state plan submission pursuant to CAA section 111(d) and an EPA-issued EG, as well as apply to the EPA when it reviews state plan submissions. The regulations also govern the EPA's development of EGs pursuant to CAA section 111(d), which apply to every state that contains designated facilities.

The Administrator finds that this is a matter on which national uniformity in judicial resolution of any petitions for review is desirable, to take advantage of the D.C. Circuit's administrative law expertise, and to facilitate the orderly development of the law under the Act. The Administrator also finds that consolidated review of this action in the D.C. Circuit will avoid piecemeal litigation in the regional circuits, further judicial economy, and eliminate the risk of inconsistent results, and that a nationally consistent approach to implementation of EGs pursuant to CAA section 111(d) constitutes the best use of agency resources.

For these reasons, this final action is nationally applicable or, alternatively, the Administrator is exercising the complete discretion afforded to him by the CAA and finds that this final action is based on a determination of nationwide scope or effect for purposes of CAA section 307(b)(1) and is publishing that finding in the **Federal Register**. Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by January 16, 2024. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Additionally, pursuant to CAA section 307(d)(1)(V), the Administrator determines that this action is subject to the provisions of CAA section 307(d). The EPA made this determination at proposal and has complied with the applicable procedural requirements in the course of this rulemaking. Section 307(d)(1)(V) of the CAA provides that the provisions of CAA section 307(d) apply to ‘‘such other actions as the Administrator may determine.’’ Section 307(d)(7)(B) of the CAA further provides that ‘‘[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period

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[1] See the EPA website, *https://www.epa.gov/tribal/tribes-approved-treatment-state-tas,* for information on those tribes that have treatment as a state for specific environmental regulatory programs, administrative functions, and grant programs.

[2] *Sierra Club* v. *EPA,* 47 F.4th 738, 745 (D.C. Cir. 2022) (‘‘EPA's decision whether to make and publish a finding of nationwide scope or effect is committed to the agency's discretion and thus is unreviewable''); *Texas* v. *EPA,* 983 F.3d 826, 834–35 (5th Cir. 2020).

[3] See, *e.g., Nat'l Waste & Recyling Ass'n* v. *EPA,* No. 16–1371 (D.C. Cir. 2016) (consolidated challenges to the CAA section 111(d) emissions guidelines for municipal solid waste landfills in the D.C. Circuit); *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021) (consolidated challenges to, among other things, the CAA section 111(d) emission guidelines for fossil fuel-fired electric generating units known as the Affordable Clean Energy Rule).

[4] In deciding whether to invoke the exception by making and publishing a finding that an action is based on a determination of nationwide scope or effect, the Administrator takes into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C. Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC South Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

The EPA notes that the individual regulatory provisions it is revising or finalizing in this action are severable from one another because each is supported by an independent rationale. That is, the individual subsections within each of the sections of subpart Ba are generally justified independently and are therefore severable for purposes of judicial review.

II. Background

A. What is the statutory authority for this action?

The statutory authority for this action is provided by CAA section 111 (42 U.S.C. 7411). As described further in the next section, CAA section 111 requires the EPA to establish standards of performance for certain categories of stationary sources that, in the Administrator's judgment, ''cause[ ], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' CAA section 111(b) provides the EPA's authority to regulate new and modified sources, while CAA section 111(d) directs the EPA to ''prescribe regulations which shall establish a procedure'' for states to submit plans to the EPA that establish standards of performance for existing sources of certain air pollutants to which a standard would apply if such existing source were a new source. The EPA addresses its obligation under CAA section 111(d) to establish a procedure for states to submit plans both through its promulgation of general implementing regulations, including those addressed by this action, and through promulgation of EGs for specific source categories. Additional statutory authority for this action is provided by section 301 of the CAA (42 U.S.C. 7601), which contains general provisions for the administration of the CAA, including the authority for the Administrator to ''prescribe such regulations as are necessary to carry out [the] functions'' of the CAA under section 301(a)(1).

B. What is the background for this action?

Clean Air Act section 111(d) governs the establishment of standards of performance for existing stationary sources. CAA section 111(d) directs the EPA to ''prescribe regulations which shall establish a procedure similar to that provided by [CAA section 110]'' for states to submit state plans that establish standards of performance for existing sources of certain air pollutants to which a standard of performance would apply if such an existing source were a new source under CAA section 111(b). Therefore, an existing source can only be regulated under CAA section 111(d) if it belongs to a source category that is regulated under CAA section 111(b). The EPA's implementing regulations use the term ''designated facility'' to identify those existing sources. *See* 40 CFR 60.21a(b).

CAA section 111(b)(1)(A) requires that a source category be included on the list for regulation if, ''in [the EPA Administrator's] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' Once a source category is listed, CAA section 111(b)(1)(B) requires that the EPA propose and then promulgate ''standards of performance'' for new sources in such source category. CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' This provision requires the EPA to determine both the best system of emission reduction (BSER) for the regulated source category and the degree of emission limitation achievable through application of the BSER. The EPA must then, under CAA section 111(b)(1)(B), promulgate standards of performance for new sources that reflect that level of stringency.

Once the EPA promulgates standards of performance for new sources within a particular source category, the EPA is required, in certain circumstances, to regulate emissions from existing sources in that same source category.[5] Under CAA section 111(d), the Agency has, to date, issued EGs regulating five pollutants from six source categories that are currently in effect (*i.e.,* sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), kraft pulp plants (total reduced sulfur), municipal solid waste landfills (landfill gases)), and fossil fuel-fired electric generating units (greenhouse gases [GHGs]). *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (March 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (October 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (April 17, 1980); ''Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills,'' 81 FR 59276 (August 29, 2016); ''Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations,'' 84 FR 32520 (July 8, 2019) (Affordable Clean Energy (ACE) Rule).[6][7] Additionally, the

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[5] In accordance with CAA section 111(d), states are required to submit plans to establish standards of performance for existing sources for any air pollutant: (1) the emission of which is subject to a Federal New Source Performance Standard; and (2) which is neither a pollutant regulated under CAA section 108(a) (*i.e.,* criteria air pollutants such as ground-level ozone and particulate matter, and their precursors, like volatile organic compound) or a hazardous air pollutant regulated from the same source category under CAA section 112. See also definition of ''designated pollutant'' in 40 CFR 60.21a(a).

[6] The EPA has also issued several EGs that have subsequently been repealed or vacated by the courts. The EPA regulated mercury from coal-fired electric power plants in a 2005 rule that was vacated by the D.C. Circuit, ''Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Final Rule,'' 70 FR 28606 (May 18, 2005) (Clean Air Mercury Rule), vacated by *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). The EPA also issued CAA section 111(d) EGs regulating GHG emissions from fossil fuel-fired electric power plants in a 2015 rule, ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule,'' 80 FR 64662 (October 23, 2015)

EPA recently proposed EGs addressing GHG emissions from two different source categories. On November 15, 2021, the EPA proposed EGs to regulate GHG emissions (in the form of methane limitations) from sources in the oil and natural gas source category (86 FR 63110) and provided a supplemental proposal for that sector on December 6, 2022 (87 FR 74702). On May 23, 2023, the EPA proposed to repeal the existing EG for GHG emissions from certain fossil fuel-fired electric generating units (the ACE Rule) and to promulgate a new EG in order to regulate GHG emissions (in the form of carbon dioxide limitations) from existing fossil fuel-fired electric generating units. 88 FR 33240. Finally, the Agency has regulated additional pollutants from solid waste incineration units under CAA section 129 and in accordance with CAA section 111(d).[8]

The mechanism for regulating designated facilities[9] under CAA section 111(d) differs from the mechanism for regulating new facilities under CAA section 111(b). Pursuant to CAA section 111(b), the EPA promulgates standards of performance that are directly applicable to new, modified, and reconstructed facilities in a specified source category. In contrast, CAA section 111(d) operates together with CAA section 111(a)(1) to collectively establish and define roles and responsibilities for both the EPA and the states in the regulation of designated facilities. Under the statutory framework, the EPA has the responsibility to determine the BSER for designated facilities, as well as the degree of emission limitation achievable through application of that BSER. The EPA identifies both the BSER and the degree of emission limitation as part of an EG, which it may typically reflect as a presumptive standard of performance or methodology for calculating a presumptive standard of performance for designated facilities. States use the EPA's presumptive standards of performance as the basis for establishing requirements for designated facilities in their state plans. In addition to standards of performance, CAA section 111(d)(1) requires state plans to include provisions for the implementation and enforcement of such standards. CAA section 111(d)(1) also requires the EPA's regulations to permit states, in applying a standard of performance to particular sources, to take into account the source's remaining useful life and other factors, a process addressed in more detail in section III.E of this preamble.

CAA section 111(d) directs the EPA to establish a procedure for the submission of state plans, which the EPA addresses both through its promulgation of general implementing regulations for section 111(d) and through promulgation of EGs for specific source categories. While CAA section 111(d)(1) authorizes states to develop state plans that establish standards of performance and provides states with certain discretion in determining the appropriate standards, CAA section 111(d)(2) provides the EPA a specific oversight role with respect to such state plans. The states must submit their plans to the EPA, and the EPA must evaluate each state plan to determine whether each plan is ''satisfactory.'' If a state fails to submit a plan or the EPA determines that a state plan is not satisfactory, the EPA has the ''same authority'' to prescribe a Federal plan as it has to promulgate a Federal Implementation Plan (FIP) under CAA section 110(c).

In 1975, the EPA issued the first general implementing regulations to prescribe the process for the adoption and submittal of state plans for designated facilities under CAA section 111(d) (codified at 40 CFR part 60, subpart B (subpart B)). 40 FR 53340 (November 17, 1975). Responding to the direction to ''establish a procedure similar to that provided by'' CAA section 110, in promulgating subpart B, the EPA aligned the timing requirements for state and Federal plans under CAA section 111(d) with the then-applicable timeframes for State Implementation Plans (SIPs) and FIPs prescribed in CAA section 110, as established by the 1970 CAA Amendments. The implementing regulations were not significantly revised after their original promulgation in 1975[10] until 2019, when the EPA promulgated a new set of implementing regulations codified at 40 CFR part 60, subpart Ba (subpart Ba). 84 FR 32520 (July 8, 2019).

In promulgating subpart Ba in 2019, the EPA intended to update and modernize the implementing regulations to align the procedures for CAA section 111(d) state and Federal plans with CAA amendments made after subpart B was first promulgated in 1975. Notably, subpart B did not align either with CAA section 111(d) as amended by Congress in 1977 or with the timelines in CAA section 110 as amended by Congress in 1990. The EPA therefore considered it appropriate to update the implementing regulations for CAA section 111(d) to make changes similar to CAA section 110, given that section 111(d)(1) of the CAA directs the EPA to ''prescribe regulations which shall establish a procedure similar to that provided by section 110'' of the CAA for states to submit plans to the EPA. In promulgating subpart Ba, the EPA directly aligned the timing requirements for CAA section 111(d) state and Federal plans (40 CFR 60.23a(a)(1) and 60.27a(c), respectively) with the timing requirements for SIPs and FIPs under CAA section 110 (see CAA section 110(a)(1) and 110(c)(1), respectively).

In promulgating subpart Ba, the EPA also added the definition of ''standard of performance'' (40 CFR 60.21a(f)) (defined under subpart B as ''emission standard'' (40 CFR 60.21(f))) and the ''remaining useful life'' provision (40 CFR 60.24a(e)) (referred under subpart B as the ''variance'' provision (40 CFR 60.24(f))). The EPA further added required minimum administrative and technical criteria for inclusion in state plans (40 CFR 60.27a(g)). Applying these criteria, the EPA determines whether a state plan or portion of a plan submitted is complete (referred to as a completeness review). Once a state plan or portion of a plan is determined to be complete, the EPA must approve or disapprove the plan or portions of the plan. For details on the EPA's rationale for the promulgation of these provisions, see 84 FR 32520 (July 8, 2019).

The EPA proposed minor revisions to the subpart Ba applicability provision and is finalizing those revisions largely as proposed (see section III.G.2.a. of this preamble). As finalized in 2019, subpart Ba was applicable to any final 111(d) EG published, or the implementation of which was ongoing, after July 8, 2019. The EPA proposed revisions to this provision for clarity, including to

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(Clean Power Plan). The EPA subsequently repealed and replaced the 2015 rule with the ACE Rule.

[7] The ACE Rule was initially vacated by *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021). The Supreme Court subsequently reversed and remanded the D.C. Circuit's opinion, *West Virginia* v. *EPA,* 142 S. Ct. 2587 (June 30, 2022). On October 27, 2022, the D.C. Circuit amended its judgement and recalled the partial mandate vacating the ACE Rule, effectively reinstating ACE. Order, *ALA* v. *EPA,* No. 19–1140, ECF No. 1970895.

[8] CAA section 129 directs the EPA Administrator to develop regulations under CAA section 111 limiting emissions of nine air pollutants from four categories of solid waste incineration units.

[9] A ''designated facility'' is any existing facility which emits an air pollutant, the emissions of which are subject to a standard of performance for new stationary sources but for which air quality criteria have not been issues and that is not included on a list published under CAA section 108(a) or 112, and which would be subject to a standard of performance for that pollutant if the existing facility were a new facility. See 40 CFR 60.21a.

[10] In 2012, the EPA revised several provisions of subpart B, mainly to include allowance systems as a form of standard of performance. 77 FR 9303 (February 16, 2012).

remove the phrase ''if implementation of such final guideline is ongoing.'' [11] It did not propose to change the already-established applicability date. At the time of promulgation of this rule, there are no final EGs that have been published after July 8, 2019, so subpart Ba will not retroactively apply to the implementation of any EG. Specifically, the final EG for greenhouse gas emissions from existing electric utility generating units that was included in the ACE Rule was published on July 8, 2019; [12] thus, subpart Ba as revised will not apply to that EG. Regardless, the EPA proposed to repeal the ACE Rule on May 23, 2023,[13] and intends to finalize its repeal, at which point neither states nor the EPA will have any obligations under the ACE Rule and the potential applicability of subpart Ba to this EG will be moot. In contrast, the EPA has recently proposed two EGs that would regulate GHG emissions from designated facilities in the oil and natural gas industry (86 FR 63110, November 15, 2021; 87 FR 74702, December 6, 2022) and in the power sector (88 FR 33240, May 23, 2023). If those EGs are finalized and to the extent that the final EGs do not contain EG-specific requirements superseding subpart Ba provisions, subpart Ba as revised in this action will apply. Subpart B continues to apply to CAA section 111 EGs promulgated on or prior to July 8, 2019, and to EGs issued pursuant to CAA section 129.

In January 2021, the D.C. Circuit vacated several provisions of subpart Ba related to timelines for state plans and Federal plans. *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914, 991. (D.C. Cir. 2021) (*ALA*).[14] In this vacatur, the court identified several flaws in the EPA's rationale for extending CAA section 111(d) state and Federal plan timelines. First, the court found that the EPA erred in adopting the timelines for SIPs and FIPs in CAA section 110 without meaningfully addressing the differences in the scale of effort required for development and evaluation of CAA section 110 SIPs, as compared with the scale of effort needed for CAA section 111(d) state plans. *Id.* at 992–93. The court also concluded that in promulgating the timelines in subpart Ba, the EPA failed to justify why the shorter deadlines under subpart B were unworkable. *Id.* at 993. Further, the court held that the EPA was required to consider the effect of its subpart Ba timelines on public health and welfare, consistent with the statutory purpose of CAA section 111(d). In the court's view, the EPA's ''complete failure to say anything at all about the public health and welfare implications of the extended timeframes'' meant that the EPA failed to consider an important aspect of the problem. *Id.* at 992 (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc.* v. *State Farm Mut. Auto. Ins. Co.* 463 U.S. 29, 43 (1983)).

Based on these reasons, the court vacated the timeline for state plan submissions after publication of a final EG (40 CFR 60.23a(a)(1)), the EPA's deadline for taking action on state plan submissions (40 CFR 60.27a(b)), the EPA's deadline for promulgating a Federal plan (40 CFR 60.27a(c)), and the timeline associated with requirements for increments of progress (IoPs; 40 CFR 60.24 (a(d)). Because of the vacatur, subpart Ba currently does not provide generally applicable timelines for state plan submissions, a deadline for the EPA's action on state plan submissions, a deadline for the EPA's promulgation of a Federal plan, or a timeline associated with requirements for IoPs. The EPA notes that while it is finalizing generally applicable timelines for the implementing regulations, a particular EG may supersede those generally applicable timelines with its own specific timelines. 40 CFR 60.20a(a)(1). This may be appropriate, for example, based on the complexity of regulating a particular source category, such as a category with a large number of disparate facilities to be regulated.

C. What changes did we propose?

On December 23, 2022, the EPA proposed several revisions to subpart Ba both to address the vacatur of the timing provisions by the D.C. Circuit in *ALA* and to further improve the state and Federal plan development and implementation process. See 87 FR 79176 (December 23, 2022). In response to the *ALA* decision, the EPA proposed timeframes for (1) state plan submittal, (2) the timeline for the EPA to determine completeness of state plans, (3) the EPA's action on state plan submissions, (4) the EPA's promulgation of a Federal plan, and (5) requirements to establish IoPs. Additionally, the EPA proposed to remove the publication in the **Federal Register** of a ''finding of failure to submit'' as the starting point for the clock to promulgate a Federal plan.

In addition, the EPA proposed revisions to subpart Ba that would enhance the provision of reasonable notice and opportunity for public participation by requiring that states, as part of the state plan development or revision process, undertake outreach and meaningful engagement with a broad range of pertinent stakeholders. The EPA proposed to define pertinent stakeholders as including communities most affected by and vulnerable to the impacts of the plan or plan revision. Increased vulnerability, as described in the proposal, may be attributable, among other reasons, to both an accumulation of negative and lack of positive environmental, health, economic, or social conditions within these populations or communities.

To improve flexibility and efficiency in the submission, review, approval, and implementation of state plans, the EPA proposed to include the following mechanisms in subpart Ba, all of which currently exist under CAA section 110: (1) partial approval/disapproval, (2) conditional approval, (3) allowance for parallel processing, (4) a mechanism for the EPA to call for plan revisions, and (5) an error correction mechanism.

The EPA also proposed revisions to the existing regulations governing the ''remaining useful life and other factors'' (RULOF) provision of the statute. These proposed revisions were intended to promote clarity and increase consistency in situations where states or the EPA consider RULOF when applying standards of performance to individual sources and to ensure that such standards fulfill the statutory requirements of CAA section 111(d).

Finally, the EPA proposed to require electronic submissions of state plans, as well as additional modifications and clarifications to subpart Ba. In particular, the EPA proposed clarifying amendments to the subpart Ba definition of standard of performance, along with a revised interpretation of CAA section 111(d) with respect to permissible compliance flexibilities. The EPA proposed to determine that, under appropriate circumstances, the Agency may approve state plans that authorize sources to meet their emission limits in the aggregate, such as through standards that permit compliance via

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[11] 87 FR 79176, 79208–09 (Dec. 23, 2022). As explained in section III.G.2.a. of this preamble, the EPA is finalizing the removal of this phrase from 40 CFR 60.20a(a).

[12] 84 FR 32520 (July 8, 2019).

[13] ''New source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule,'' 88 FR 33240 (May 23, 2023).

[14] The Supreme Court subsequently reversed and remanded the D.C. Circuit's opinion. *West Virginia* v. *EPA,* 142 S.Ct. 2587 (June 30, 2022). However, no Petitioner sought certiorari on, and the Supreme Court's *West Virginia* decision did not implicate, the D.C. Circuit's vacatur of portions of subpart Ba. *See* Amended Judgment, *ALA* v. *EPA,* No. 19–1140 (D.C. Cir. October 27, 2022), ECF No. 1970898 (ordering that petitions for review challenging the timing portion of implementing regulations be granted).

trading or averaging. In doing so, the EPA also proposed to conclude that CAA section 111 does not limit the BSER to controls that can be applied at and to the source.

The EPA did not reopen any subpart Ba requirements other than the specific provisions that the EPA explicitly proposed to revise in the December 2022 notice of proposed rulemaking. Any comments received on the proposal that did not relate to the proposed revisions or additions are considered out of the scope of this action.

D. What outreach and engagement did the EPA conduct?

The EPA conducted both pre- and post-proposal outreach and meaningful engagement events with environmental justice (EJ) communities, small businesses, states, and Tribes. On July 7 and July 11, 2022, the EPA conducted two pre-proposal webinars for states addressing meaningful engagement for pertinent stakeholders, and on July 26, 2022, the Agency conducted a pre-proposal webinar for EJ communities and other key stakeholders about potential requirements for states to conduct meaningful engagement in developing their state plans. The EPA emailed an announcement of the subpart Ba proposal to Tribal nations and environmental justice communities via existing listservs on December 15, 2022. Post-proposal outreach during the public comment period with environmental justice communities included participation on the January 24, 2023 Environmental Justice National call and the January 26, 2023 National Tribal Air Association call. The EPA also conducted a public training webinar on January 31, 2023, for environmental justice community members and their representatives. Additionally, the EPA conducted post-proposal outreach with small businesses through the Small Business Environmental Assistance Program call on February 21, 2023, and with state environmental protection associations including the Association of Air Pollution Control Agencies on January 10, 2023, and the National Association of Clean Air Agencies on February 8, 2023.

III. What actions are we finalizing and what is our rationale for such decisions?

This action finalizes amendments to subpart Ba, including the timing requirements for state plan submittal, the EPA's action on state plan submissions, the EPA's promulgation of a Federal plan, and the establishment of IoPs; the addition of five regulatory mechanisms to improve state plan processing: (1) partial approval/disapproval, (2) conditional approval, (3) allowance for parallel processing, (4) a mechanism for the EPA to call for plan revisions, and (5) an error correction mechanism; new requirements for meaningful engagement with pertinent stakeholders; and amended requirements for states' and the EPA's consideration of RULOF in applying a standard of performance in certain circumstances. This action also finalizes amendments to the subpart Ba definition of ''standard of performance'' and finalizes clarifications associated with CAA section 111(d) compliance flexibilities. Finally, this action finalizes requirements for the electronic submission of state plans and several other clarifications and minor revisions to the implementing regulations. While the EPA is finalizing most amendments as proposed, in response to comments submitted on the proposal, the EPA is extending the state plan submittal timeline and the timeline for requirement of IoPs; providing for additional flexibility and guidance for meaningful engagement; as well as revising and streamlining the requirements for accounting for RULOF in applying a less-stringent standard. There are also other provisions that we are finalizing with slight revisions relative to proposal. Further detail is provided in the following sections of this preamble and additional detailed responses to comments are located in the response to comment document (RTC).

While this action amends the generally applicable requirements of subpart Ba, the EPA has recognized that, under certain circumstances, some provisions of the implementing regulations may not fit the needs of a specific EG. Therefore, the existing implementing regulations provide that each EG may include specific implementing provisions in addition to or that supersede the requirements of subpart Ba. 40 CFR 60.20a(a)(1). The EPA will address source category-specific circumstances or facts that are not accommodated by the general provisions of subpart Ba through a specific EG, as the time and processes needed for development and adoption of state plans to implement the EG may be affected by unique characteristics of a source category. For example, if a proposed EG addresses a particularly large and complex source category that necessitates a relatively long timeframe for state planning, the EPA may provide a state plan submission deadline that is longer than the 18 months being finalized for subpart Ba.[15]

A. Revised Implementing Timelines

As described in section II.A. of this preamble, the subpart Ba timing requirements were vacated by the D.C. Circuit in the *ALA* decision. These vacated timing requirements include: the timeline for state plan submissions, the timeline for the EPA to act on a state plan, the timeline for the EPA to promulgate a Federal plan, and the timeline that dictates when state plans must include IoPs. These timelines are all critical to ensuring that the emission reductions anticipated by the EPA when promulgating an EG become federally enforceable measures that are timely implemented by the designated facilities.

The EPA proposed the following timelines to replace those vacated in *ALA* (87 FR 79176, Dec. 23, 2022): 15 months for state plan submissions after publication of a final EG; 60 days after submission for the EPA to determine if a plan is complete; 12 months for the EPA to take final action on a complete state plan (*i.e.,* approve, disapprove); 12 months for the EPA to promulgate a Federal plan either after the state plan submission deadline if a state has failed to submit a complete plan, or after the EPA's disapproval of a state plan submission; and requiring state plans to include IoPs if the plan requires final compliance with standards of performance later than 16 months after the plan submission deadline.[16]

The EPA received numerous comments on these proposed timelines, most of which expressed support for timelines longer than those proposed. Some commenters asserted that the *ALA* decision does not direct the EPA to necessarily reduce timelines from those vacated, only to justify the timelines more fully. In particular, most commenters expressed the need for a longer state plan submittal timeline in order to accommodate state regulatory processes associated with plan submittals (*i.e.,* legislative and/or administrative state processes), as well as to accommodate technical development of the plans and to implement the proposed meaningful engagement requirements. However, a few commenters noted that the EPA should not accommodate all lengthy state administrative processes that would unnecessarily postpone emission-reduction obligations. Some

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[15] See, *e.g.,* 88 FR 33240, 33402–03 (May 23, 2023) (proposing a 24-month state plan submission deadline for the EG for GHG emissions from fossil fuel-fired electric generating units).

[16] See 87 FR 79176, 79181–90 (Dec. 23, 2022).

commenters asserted that if the EPA were to finalize the state plan submittal timeline as proposed, the EPA should include a mechanism in the rule for states to request for extensions for state plan submittals.

While some commenters also asserted the need for longer timelines associated with the EPA's obligations to take action on a state plan submittal and to promulgate a Federal plan when required, as well as allowing a longer timeline before IoPs are required in the state plans, other commenters supported the proposed timelines for these milestones based, among other concerns, on the need for timely protection of health and welfare and in consideration of the EPA's ability to extend timelines if warranted in a particular EG.

In consideration of these comments and for the reasons described in detail in the sections that follow, the EPA is finalizing extended timelines from those proposed for submission of state plans, for significant state plan revisions, and for when IoPs must be considered for inclusion in state plans. The EPA is finalizing the remaining timelines as proposed. The EPA determined that these timelines will appropriately balance the need to reasonably accommodate the processes generally required by states and the EPA to develop, evaluate, and adopt plans to effectuate the EG with the need to ensure that designated facilities control emissions of dangerous pollutants as expeditiously as reasonably possible, consistent with the health and welfare-based objectives of CAA section 111(d). A summary of the timelines finalized in this action is shown in Table 1.

The final subpart Ba timelines are applicable to any final EG published pursuant to CAA section 111(d) after July 8, 2019, including, if finalized, those recently proposed to regulate GHG emissions from sources in the oil and natural gas industry (86 FR 63110, November 15, 202187 and FR 74702, December 6, 2022) and those proposed to regulate GHG emissions from fossil fuel-fired electric generating units (88 FR 33240, May 23, 2023), to the extent that the final EGs do not contain provisions superseding any of these timelines in subpart Ba.[17]

TABLE 1—FINAL 40 CFR PART 60, SUBPART Ba, TIMELINE COMPARED WITH THOSE INITIALLY PROPOSED, VACATED FROM SUBPART Ba, AND FROM SUBPART B

Process step	2023 Subpart Ba final	2022 Subpart Ba proposal	Subpart Ba (2019) vacated timelines	Subpart B (1975)
State Plan submittal after publication of EG in the **Federal Register**.	18 months	15 months	36 months	9 months.
State Plan completeness determination.	60 days after State Plan submission.	60 days after State Plan submission.	*6 months after State Plan submission.	N/A.
State Plan evaluation	12 months after completeness.	12 months after completeness.	12 months after completeness.	4 months after State Plan submittal deadline.
EPA Federal Plan promulgation.	12 months after failure to submit or disapproval.	12 months after failure to submit or disapproval.	24 months after finding of failure to submit or disapproval.	6 months after State Plan submittal deadline.
Requirements for Increments of Progress after submittal deadline.	If compliance is >20 months.	If compliance is >16 months.	If compliance is >24 months.	If compliance is >12 months.

* Although the timeline for the state plan completeness determinations was not vacated, the EPA has evaluated this timeline light of the court vacatur of the related timelines.

As described in greater detail in section II. of this preamble, the D.C. Circuit's vacatur of the extended timelines in subpart Ba was based both on the EPA's failure to substantiate the necessity for the additional time at each step of the administrative process, and the EPA's failure to address how those extended implementation timelines would impact public health and welfare. Accordingly, the EPA has evaluated these factors and is finalizing timelines, as described in the following sections, based on the minimum administrative time reasonably necessary for each step in the implementation process, thus minimizing impacts on public health and welfare by proceeding as expeditiously as reasonably possible while accommodating the time needed for states or the EPA to develop an effective plan. This approach addresses both aspects of the *ALA* decision because the EPA and states will take no longer than necessary to develop and adopt plans that impose requirements consistent with the overall objectives of CAA section 111(d).

The EPA acknowledges these timelines are not identical to those for SIPs under CAA section 110. This is consistent with the requirement of CAA section 111(d) that the EPA promulgate a procedure ''similar'' to that of CAA section 110, rather than an identical procedure. This is also consistent with the *ALA* decision, which requires the EPA to ''engage meaningfully with the different scale'' of CAA section 111(d) and 110 plans. 985 F.3d at 993. In proposing the revised timelines, the EPA evaluated each step of the state plan implementation process to independently determine the appropriate duration needed to accomplish a given step as part of the overall process. After receiving comments on the proposed timelines, the EPA again evaluated each step in light of the new information; the timelines being finalized in this action represent the Agency's revised assessment of the most reasonably expeditious timelines that are appropriate to provide as a default for EGs under these generally applicable implementing regulations.

The EPA recognizes that, under certain circumstances, the timelines being finalized in this action may not fit the needs of a specific EG because of the specific characteristics of an EG. The EPA will address source category-specific circumstances or facts that are not accommodated by the timelines of subpart Ba through a specific EG. Examples of circumstances that may require consideration for different

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[17] Under each of these EGs the EPA proposed to supersede the 15-month state plan submittal timeline in proposed subpart Ba based on the size and complexity of the source sectors at issue.

timelines could include EGs that require states to perform extensive engineering and/or economic analyses before submitting their plans; EGs with an exceptional need to expedite implementation (*e.g.,* in order to address immediate health and welfare impacts); EGs that apply to an extraordinary number of disparate designated facilities; or EGs that are novel and/or unusually complex. For situations like these, 40 CFR 60.20a(a)(1) provides that an EG may supersede any aspect of the implementing regulations, including the implementation timelines. It is within the EPA's discretion to determine whether a proposed change in implementation time may be justified within an individual EG based on these or other appropriate factors. For EGs that supersede implementation timelines, the EPA will, in the EG, both provide a justification for the differing timelines and address how the change in timeline will impact health and welfare.

1. State Plan Submission Timelines

This section discusses the amount of time states will have to submit plans and plan revisions to the EPA following the publication of a final or revised EG in the **Federal Register**. As described in further detail in section III.E of this preamble, under CAA section 111(d), the EPA first determines a BSER and the degree of emission limitation for designated facilities and promulgates these determinations in an EG. CAA section 111(a)(1), 40 CFR 60.22a(b)(5). It is then each state's obligation to submit a plan to the EPA which establishes standards of performance based on the EG for each designated facility. See CAA section 111(d)(1), 40 CFR 60.24a(c). The implementing regulations promulgated in 1975 under subpart B provide that states have 9 months to submit a state plan after publication of a final EG. 40 CFR 60.23(a)(1). In 2019, the EPA promulgated subpart Ba and provided 3 years for states to submit plans or plan revisions for subsequently promulgated or revised EGs, consistent with the timelines provided for submission of SIPs pursuant to CAA section 110(a)(1). This 3-year timeframe was vacated by the D.C. Circuit in the *ALA* decision, and thus currently there is no applicable deadline for state plan submissions and revisions required under EGs subject to subpart Ba.

As laid out in the notice of proposed rulemaking and summarized below, in evaluating the appropriate timeline for plan submittal to replace the vacated provisions in subpart Ba, the EPA reviewed steps that states need to carry out to develop, adopt, and submit a state plan to the EPA, and its history in implementing EGs under the timing provisions of subpart B. The EPA further evaluated the statutory deadlines and processes for relatively comparable state plans under CAA section 129, and attainment planning SIPs submitted pursuant CAA sections 189(a)(2)(B) and 189(b)(2) for the 2012 National Ambient Air Quality Standards (NAAQS) for fine particulate matter ($PM_{2.5}$). 78 FR 3085 (January 15, 2013). Finally, the EPA incorporated consideration of the *ALA* decision addressing expediency in implementation of EGs for protection of public health and welfare.

To develop a CAA section 111(d) state plan, a state must complete a series of steps to ensure that the plan will meet all applicable requirements. Subpart Ba specifies the elements that must be included in a state plan submission (see 40 CFR 60.24a, 60.25a, 60.26a) as well as certain processes that a state must undertake in adopting and submitting a plan (see 40 CFR 60.23a). In addition to the requirements of these implementing regulations, there are also state-specific processes applicable to the development and adoption of a state plan, including the administrative processes (*e.g.,* permitting processes, regulatory development, legislative approval) necessary to develop and adopt enforceable standards of performance. State plan development generally involves several phases, including providing notice that the state agency is considering adopting a rule; taking public comment; and approving or adopting a final rule. The process required to formally adopt a rule at the state level differs from state to states.[18]

As previously mentioned, subpart B provides 9 months for states to submit plans after publication of a final EG. The EPA's review of state's timeliness for submitting CAA section 111(d) plans under the 9-month timeline indicated that most states either did not submit plans or submitted plans that were substantially late.[19] The EPA also noted that the plans submitted under subpart B were not subject to additional requirements for meaningful engagement and consideration of RULOF, which may add time to the state development process relative to plans developed and submitted under subpart B. For these reasons, the EPA found that 9 months is not a reasonable amount of time for most states to adequately develop a plan for an EG.

To help inform the proposal for the state plan submission deadline, the EPA also reviewed CAA section 129's statutory deadline and requirements for state plans, and the timeliness and responsiveness of states under CAA section 129 EGs. CAA section 129 references CAA section 111(d) in many instances, creating considerable overlap in the functionality of the programs. The processes for CAA sections 111(d) and 129 are similar in that states are required to submit plans to implement and enforce the EPA's EGs. However, there are some key distinctions between the two programs, most notably that CAA section 129(b)(2) specifies that state plans be submitted no later than 1 year from the promulgation of a corresponding EG, whereas the statute does not specify a particular timeline for state plan submissions under CAA section 111(d). Moreover, CAA section 129 plans are required by statute to be at least as protective as the EPA's EGs, without exception. CAA section 129(b)(2). While CAA section 111(d) permits states to take into account remaining useful life and other factors to set less stringent standards for particular sources. This suggests that the development of a CAA section 111(d) plan could involve more complicated analyses than a CAA section 129 plan and that a longer timeframe is likely reasonable for state plans under CAA section 111(d) than the 1-year timeframe the statute provides under CAA section 129.

Additionally, the EPA found that a considerable number of states have not made timely state plan submissions in response to previous CAA section 129 EGs. In instances where states submitted CAA section 129 plans, a significant number of states submitted plans between 14 to 17 months after the promulgated EG.[20] This again suggests that states will typically need more than

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[18] In many states, the agency must submit its rule to a particular independent commission or the legislature for review and approval before the rule is finally adopted. Generally, adopted rules are filed with a state entity, such as the secretary of state, and eventually published in a register and placed into the state's administrative code. State law establishes when an adopted rule is effective.

[19] The EPA reviewed the information available in 40 CFR part 62. The supporting information reviewed is available at Docket ID No. EPA–HQ–OAR–2021–0527. Part 62 codifies the Administrator's approval and disapproval of state plans for the control of pollutants and facilities under CAA section 111(d), and under CAA section 129 as applicable, and the Administrator's promulgation of such plans or portions of plans thereof.

[20] The EPA reviewed the information available in 40 CFR part 62. The supporting information reviewed is available at Docket ID No. EPA–HQ–OAR–2021–0527. Part 62 codifies the Administrator's approval and disapproval of state plans for the control of pollutants and facilities under CAA section 111(d), and under CAA section 129 as applicable.

one year to develop a state plan to implement an EG.

In the 2019 promulgation of subpart Ba, the EPA mirrored CAA section 110 by giving states 3 years to submit plans. As previously described, the D.C. Circuit faulted the EPA for adopting the CAA section 110 timelines without accounting for the differences in scale and scope between CAA section 110 and 111(d) plans. Therefore, in proposing the revised timelines the EPA closely evaluated other statutory deadlines and requirements for state implementation plans to determine what is feasible for a CAA section 111(d) state plan submission timeline. The EPA specifically focused on statutory SIP submission deadlines and requirements in the context of attainment plans for the 2012 $PM_{2.5}$ NAAQS under CAA section 189 because it provided a comparable process. CAA section 189(a)(2)(B) requires states to submit attainment planning SIPs within 18 months after an area is designated nonattainment and there is a record of successful state submittals pursuant to this timeline. The 2012 $PM_{2.5}$ NAAQS attainment plans were, in most cases, more complicated for states to develop when compared to a typical plan that may be required under CAA sections 111(d). For example, attainment plans require states to determine how to control a variety of sources, based on extensive modeling and analyses, in order to bring a nonattainment area into attainment of the $PM_{2.5}$ NAAQS by a specified date. Identification of contributing emission sources and the development of effective control strategies can be challenging because particulate matter pollution is comprised of both primary emissions and secondary particle formation. By contrast, under CAA section 111(d), it is clear which designated facilities are subject to a state plan, in general what control methods are available for the designated pollutant from that facility, and that the standards of performance for these sources must reflect the level of stringency for the facility as determined by the EG unless a state chooses to account for RULOF.

Informed by these analyses, the EPA proposed to require that each state adopt and submit to the Administrator a plan for the control of the designated pollutant(s) to which the EG applies within 15 months of publication of a final EG. Some commenters supported the proposed timeline based on the need for urgency in achieving the emission reductions targeted by an EG. Additionally, some commenters noted that, in comparison with NAAQS SIP requirements, states are generally well-positioned to address the source sectors historically regulated under CAA section 111(d) and have access to information about control strategies and regulatory approaches for controlling emissions. Most commenters on this issue were state agencies or other state-related entities that generally expressed the need for a longer state plan submittal timeline in order to accommodate state regulatory processes associated with plan submittals (*i.e.,* legislative and/or administrative state processes), as well as to accommodate technical development of the plans and to implement the proposed meaningful engagement requirements. Approximately 10 states responded to the EPA's request with information about their state processes. The information received indicates that states argued that they need anywhere from 15 months to 36 months to adopt and submit state plans. As discussed further below, the EPA is finalizing a state plan submittal timeline of 18 months. It is doing so after consideration of comments received on the proposal and recognizing the need to protect public health and welfare. The EPA has determined that 18 months is the appropriate timeline for these general implementing regulations; for a generic EG, this represents a reasonable balance between providing states sufficient time to develop and submit a plan that satisfies the applicable requirements and ensuring that the emission reductions contemplated in an EG are achieved as expeditiously as practicable. Consistent with the existing regulations of subpart Ba, 40 CFR 60.20a(a)(1), the EPA may supersede this 18-month state plan submittal timeline in an individual EG.

The proposed 15-month submittal timeline was based on the EPA's proposed determination that this was a reasonably expeditious deadline that would provide states and stakeholders sufficient time to develop and submit an approvable state plan. However, based on public comments received, we no longer believe that 15 months will provide sufficient time to complete the substantive and procedural requirements under subpart Ba. For example, the EPA is revising subpart Ba to require that states demonstrate meaningful engagement as part of their state plan development. While the time needed to conduct meaningful engagement will depend highly on the source category, the designated pollutant, and the types of impacts associated with designated facilities and potential controls, as well as on the pertinent stakeholders under a given EG within each state, it is very likely to require additional time relative to the existing public notice and hearing requirements under CAA section 110 and subpart Ba. We received comments that 15 months would be insufficient time to identify pertinent stakeholders, develop public participation strategies, and conduct outreach and engagement. Some commenters also pointed out that adding requirements, such as meaningful engagement and RULOF, without a corresponding extension of time to develop plans may undermine states' abilities to submit timely, approvable plans. While some commenters requested 36 months to submit state plans, several indicated that a minimum timeframe of 18 months would be appropriate for a state plan under a generic EG. Given the preponderance of comments suggesting that 15 months was not a reasonable amount of time to develop an approvable state plan and in recognition of the need to promulgate a timeline that achieves emission reductions as expeditiously as practicable, the EPA believes 18 months is the most reasonable timeline to include in these generally applicable implementing regulations.

The EPA acknowledges that, as commenters asserted, state regulatory and legislative processes and resources can vary significantly and influence the time needed to develop and submit state plans (*e.g.,* legislative procedures and timelines vary by state). Some commenters opposed to a shorter state plan submission timeline asserted that they need 36 months to complete their administrative and legislative processes. However, because the CAA contains numerous, long-standing requirements under other programs for states to develop and submit plans within 18 months (or fewer),[21] the EPA believes that states should be well positioned to accommodate an 18-month submittal timeline for plans under section 111(d). In designing a submittal deadline for state plans, it is reasonable to look to what Congress has determined are appropriate timelines for SIPs and to assume that states should be able to accommodate comparable timelines under CAA section 111(d). Indeed, some commenters recommend that the EPA not defer to lengthy state administrative processes, and expressed concern that some states have adopted, or may adopt, procedures that are longer than necessary and that will unnecessarily postpone Federal emission-reduction obligations. To this point, extending

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[21] See, *e.g.,* CAA sections 110(k)(5); 129; 179(d)(1); 189.

state plan submittal timelines to account for any and all unique state procedures would inappropriately delay reductions in emissions that have been found under CAA section 111 to endanger health or the environment.

Some commenters asserted that the *ALA* decision does not preclude the EPA from adopting a 36-month time frame for state plan submittals and that the Agency need only justify a longer timelines more fully. However, the EPA recognizes that the D.C. Circuit, in *ALA,* faulted the Agency for failing to consider the potential impacts to public health and welfare associated with extending planning deadlines. In response, the EPA is promulgating a state plan submittal timeline that reflects the generally expeditious period of time for states to develop and submit a plan per the corresponding emission guidelines that is both comprehensive and legally sound. The EPA does not interpret the court's direction to require a quantitative measure of impact, but rather consideration of the importance of meeting the public health and welfare goals when determining appropriate deadlines for implementation of regulations under CAA section 111(d). Based on EPA's assessment of the time it will take for states to develop and submit plans under these general implementing regulations, both in the notice of proposed rulemaking and this preamble and after consideration of comments received, the EPA has determined that 18 months represents the generally expeditious period of time.

Some commenters stated that reduction of the designated pollutants addressed by currently proposed emission guidelines (*i.e.,* GHG) is not urgent based on the fraction of global GHG reduced by currently proposed emission guidelines, so a longer state plan timeline would be justified. The EPA disagrees with the commenters' characterizations of the threat posed by elevated concentrations of greenhouse gases in the atmosphere. The EPA has determined that greenhouse gas air pollution may reasonably be anticipated to endanger public health or welfare[22] and has explained that ''scientific assessments, EPA analyses, and documented observed changes in the climate of the planet and of the U.S. present clear support regarding the current and future dangers of climate change and the importance of GHG emissions mitigation.''[23] Moreover, subpart Ba applies to any EG promulgated after July 8, 2019, not only to the recently proposed EGs addressing GHG emissions from two source categories. The EPA regulates source categories, through EGs, that emit pollutants the Agency has determined under CAA section 111(d) to cause or significantly contribute to an endangerment of public health or welfare. Accordingly, consistent with *ALA,* it is appropriate for the EPA to set an expeditious but reasonable schedule in these general provisions for state plan development and submission to ensure that emission reductions occur in a timely manner.

Finally, some commenters asserted that if the EPA were to finalize the state plan submittal timeline as proposed, the EPA should include a mechanism in subpart Ba for states to ask for extensions of the state plan submittal deadline. However, as we are providing additional time for state plan submittals relative to proposal, we are not providing a mechanism for states to request deadline extensions in subpart Ba. Additionally, the EPA has the ability to supersede the timelines in subpart Ba in individual EGs and will take into account any unique considerations that may result in the need for longer or shorter timelines on an EG-by-EG basis.

In summary, while the EPA proposed a 15-month state plan submittal timeline, after consideration of comments, the EPA is finalizing 40 CFR 60.23a(a)(1) to provide an 18-month timeline for the submission of state plans following publication in the **Federal Register** of a final EG. The EPA has determined that this is the generally expeditious period in which states can create and submit a plan per the EPA's corresponding EGs that is both comprehensive and legally sound. In considering the appropriate timeline, the EPA has evaluated data from previously implemented EGs and the statutory deadlines and data from analogous programs (*e.g.,* CAA sections 129 and 189). We have also considered comments that some of the requirements the EPA had proposed for subpart Ba would require additional time to implement, as well as comments asserting that certain states need up to 36 months to complete their administrative and legislative processes. While a reasonable state plan submittal timeline must provide states sufficient time to develop and submit plans that comport with the applicable requirements, the EPA also believes that state processes should be able to accommodate an 18-month timeline because the CAA already contains numerous deadlines that require SIP submissions to be developed and submitted to the Agency within 18 or fewer months. Thus, this finalized timeline should provide states reasonable time to adopt and submit approvable plans, and is also sufficiently expeditious to protect against significant adverse impacts to health and welfare resulting from foregone emission reductions during the state planning process. Providing states sufficient time to develop feasible implementation plans for their designated facilities that adequately address public health and environmental objectives also ultimately helps ensure more timely implementation of an EG, and therefore achievement in actual emission reductions, than would an unattainable deadline. Because 18 months is an expeditious time period, it follows that the EPA has appropriately considered the potential impacts to public health and welfare associated with this extension of time by providing no more time than the states reasonably need to ensure a plan is comprehensive and timely.

The EPA is also finalizing the proposed amendment to 40 CFR 60.27a(a) replacing the word ''shorten'' with ''amend''. The applicability provision at 40 CFR 60.20a(a)(1) states that ''each emission guideline may include specific provisions in addition to or that supersede requirements of this subpart.'' However, the existing provision in 40 CFR 60.27a(a) only provides for the Administrator to ''shorten the period for submission of any plan or plan revision or portion thereof.'' To make these two provisions consistent in light of the timelines for plan submission finalized in this action, the EPA is replacing the word ''shorten'' with ''amend.'' One commenter opposed the amendment stating there is no regulatory certainty for the state in state plan submittal if the Administrator can simply change the timeline as he deems necessary. However, the appropriate timeline would undergo notice and comment rulemaking as the EG is proposed and finalized so that states would have sufficient notice of the timeline. To the extent the EPA considers deviating from this 18-month timeframe in promulgating an EG in the future, the EPA will consider the public health and welfare impacts associated with extending the state plan submission timeline, consistent with the D.C. Circuit's direction in *ALA.*

The EPA is also finalizing two amendments to 40 CFR 60.28a(a), which addresses plan revisions by the state. First, the EPA is finalizing the proposed clarification that meaningful engagement requirements apply to any significant plan revision by the state. Second, the EPA is finalizing revisions

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[22] See, *e.g.,* 80 FR 64510, 64530 (Oct. 23, 2015).

[23] 88 FR 33240, 33252 (May 23, 2023).

to the timeline for state plan revisions required in response to a revised emission guideline. At proposal, the EPA indicated in the revised regulatory text that it was proposing to shorten the timeline for state plan revisions in this specific circumstance from three years to 12 months.[24] The EPA received comments on this proposed revision asserting that the same process-related challenges that apply to initial state plan submissions, including conducting meaningful engagement and RULOF procedures and working through states' administrative and legislative processes, also apply to state plan revisions. Commenters requested that the EPA extend the timeline for state plan revisions in response to revised emission guidelines; one commenter specifically requested that the EPA leave it at 36 months. However, the EPA anticipates that, in most instances, plan revisions required in response to a revised emission guideline would be narrower in scope than the initial state plan and would not require states to reevaluate standards of performance or conduct significant new analysis. For example, the EPA may revise an emission guideline to provide for additional or updated monitoring or compliance protocols or to clarify applicability provisions. In such instances, the full period of time provided for initial state plan development and submission would not be necessary.[25] Thus, the EPA believes it is reasonable to set a default timeline for the submission of state plan revisions in these general implementing guidelines that is shorter than the timeline for initial state plan submission. Because the EPA is providing an additional three months for state plan submission in this final rule relative to the proposed timeline (18 months versus 15 months), it is finalizing a timeline for the submission of state plan revisions in response to a revised emission guideline of fifteen months, which is also three months longer than the twelve months proposed. Additionally, in recognition that some state plan revisions in response to a revised emission guideline may in fact be more complex or necessitate additional analysis or rulemaking, the EPA is finalizing the provision at 40 CFR 60.28a(a) to allow the Agency to determine a different timeline for the submission of revised state plans, which it will provide in the revised emission guideline.

2. Timeline for the EPA To Determine Completeness of State Plans

Once a state plan has been submitted to the EPA, the EPA reviews the plan for ''completeness'' to determine whether it includes certain elements necessary to ensure that the EPA can substantively evaluate the plan. The EPA determines completeness by comparing the state's submission against the administrative and technical criteria specified in subpart Ba to determine whether the submission contains the specified elements (see 40 CFR 60.27a(g)(2) for completeness criteria). The timeline to make completeness determinations in the version of subpart Ba the EPA promulgated in 2019 mirrored the language for SIPs in CAA section 110(k)(1)(B): ''Within 60 days of the Administrator's receipt of a plan or plan revision, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria [for completeness] have been met.'' Like CAA section 110(k)(1)(B), subpart Ba also provided that a state plan would be deemed complete by operation of law if the EPA had not made an affirmative determination by the date 6 months after receipt of the plan submission. 40 CFR 60.27a(g)(1).

After a state plan is deemed complete through either an affirmative determination or by operation of law, the EPA will act on the state plan submission through notice-and-comment rulemaking. The timeline for the EPA to act on a state plan submission runs from the date a submission is deemed complete; more on this timeline can be found in section III.A.3. of this preamble.

If a state plan submission does not contain the elements required by the completeness criteria, the EPA would find that the state has failed to submit a complete plan and notify the state through a letter. The determination of incompleteness treats the state as if the state has made no submission at all. The determination that a submission is incomplete and that the state has failed to submit a plan is ministerial in nature.

As part of the EPA's overall effort to set implementation timelines under CAA section 111(d) that are as expeditious as possible, the EPA proposed to revise the timing element of the completeness review at 40 CFR 60.27a(g)(1). In light of the ministerial nature of the completeness determination, the EPA proposed a maximum of 60 days from receipt of the state plan submission for the EPA to make a determination of completeness. The EPA additionally proposed that any state plan or plan revision submitted to the EPA that has not received a completeness determination within 60 days of receipt, shall on that date be deemed, by operation of law, to meet the completeness criteria, which will trigger the EPA's obligation to take substantive action on the state plan. Sixty days provides an expeditious timeframe for the EPA to evaluate state plans for completeness and to notify the states of the determination. Because the EPA may be required to evaluate up to 50 state plans during this period, in addition to plans submitted by territories and tribes, the EPA explained at proposal that it did not find that this timeframe could reasonably be shortened any further.

While most commenters supported the 60-day completeness period, some commenters expressed concern that a state plan that is automatically deemed complete by operation of law as of the allotted 60 days could cause unnecessary turbulence in state plan implementation if the plan is later disapproved by the EPA due to missing information. Other commenters noted that if a plan is determined to be incomplete, a 60-day period will not allow states sufficient time to correct the deficiency and submit a complete plan. First, the EPA notes that the completeness determination is ministerial in nature and does not affect the Agency's subsequent responsibility and authority to substantively review a state plan submission against the requirements of the Act and applicable regulations, including this subpart Ba and the relevant EG. That is, a determination that a state plan is complete does not signify that it necessarily satisfies the substantive requirements. The commenters fail to explain how deeming a state plan submission complete by operation of law, in this case after 60 days, and later finding it does not satisfy an applicable requirement is a new phenomenon or would cause unnecessary turbulence in state plan implementation. Rather, a shorter period for deeming plans complete by operation of law would be less disruptive than a longer period in this instance because the EPA will complete its substantive evaluation of the plan sooner and the state will have notice earlier on of any deficiencies. Additionally, because states may submit plan revisions at any time, states may

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[24] ''Docket_memo_outlining_proposed_changes_to_regulatory_text.pdf,'' *available at https://www.epa.gov/stationary-sources-air-pollution/adoption-and-submittal-state-plans-designated-facilities-40-cfr,* as well as Docket ID No. EPA–HQ–OAR–2021–0527–0002.

[25] The EPA's response to comments that the state plan submission timelines should accommodate every state's unique administrative and legislative processes is also relevant here and is provided elsewhere in this section of the preamble.

work collaboratively with the EPA on any portions of a plan identified as being deficient during both the completeness determination period and the period for the EPA's substantive review of the plan. Thus, again, a shorter completeness determination period that includes a cutoff for deeming submissions complete by operation of law merely keeps the state plan review process moving expeditiously and does not foreclose any state opportunities to correct or supplement submissions at any point in the EPA's review process.

Moreover, the EPA intends to review for completeness as soon as possible after submittal. Although the EPA believes that it will be able to provide a timely completeness determination for most if not all state plan submissions, providing for completeness through operation of the law will help ensure that the EPA's action on state plans does not significantly delay plan processing or implementation.

The EPA is therefore finalizing the completeness provision at 40 CFR 60.27a(g)(1) as proposed. The EPA notes that if the EPA determines a plan is incomplete, the EPA is required to promulgate, through notice-and-comment rulemaking, a Federal plan. See sections III.A.4. and III.B. for the discussion and final amendments associated with the timeline and triggers of the Federal Plan respectively. If a state submits a plan prior to the state plan submission deadline and the EPA also makes a determination that the plan is incomplete prior to that deadline, the EPA will treat the state as if the state has made no submission at all, but this determination does not yet trigger further action by the EPA. Instead, because the state still has an opportunity to submit a complete plan before the state plan submission deadline, the EPA's authority to promulgate a Federal plan is only triggered if the state fails to timely submit a new plan to replace the incomplete plan by the state plan deadline.

3. Timeline for the EPA's Action on State Plans

After a state plan has been determined to be complete or is deemed complete by operation of law, CAA section 111(d) provides that the EPA must evaluate whether the plan is ''satisfactory''; that is, whether the components of the plan meet all the requirements of the statute, these implementing regulations, and the corresponding EG. The EPA does so by evaluating a plan (or plan revision) to determine whether the plan or plan revision is approvable, in part or in whole (see section III.D.1. of this preamble for discussion on partial plan approvals), through a notice-and-comment rulemaking process. After the EPA proposes an action on a state plan submission (*e.g.,* approval, partial approval/partial disapproval, disapproval) and reviews comments on the proposed action, the EPA will finalize its action on the plan. If the EPA approves a state plan, the standards of performance and other components of that state plan become federally enforceable. If the state plan is disapproved, in part or in whole, the EPA is obligated to promulgate a Federal plan for designated facilities within the state that were covered by the disapproved portions of the plan (see section III.A.4. of this preamble below for the EPA's timeline to publish a Federal plan).

Subpart B requires the EPA to take action on applicable state plans (*e.g.,* approve or disapprove) within 4 months after the date required for submission. 40 CFR 60.27(b). In the development of subpart Ba, the EPA contended that 4 months was an inadequate time to review and take action on state plans and therefore instead provided a deadline of 12 months for final action on a state plan (mirroring the maximum time permitted under CAA section 110(k)(1)(2) for the EPA's action on complete SIPs). 84 FR 32520, July 8, 2019. In the *ALA* decision, the D.C. Circuit vacated this revised timeline in subpart Ba on the basis that the EPA did not adequately justify the extended timeframes and did not consider the public health and welfare impacts of extending the implementation times. As is discussed below, the EPA has in this rulemaking closely evaluated the process, steps, and timeframes for the EPA to substantively review and act upon each state plan submission through a public notice-and-comment rulemaking process. After considering the time anticipated to be necessary for generally expeditious EPA action on state plans, the EPA again proposed that it must take final action on a state plan or plan revision submission within 12 months after a plan is determined to be complete or becomes complete by operation of law.[26]

In the notice of proposed rulemaking, the EPA explained that the first step it takes once a state plan submittal has been deemed ''complete'' under 40 CFR 60.27a(g) is for an intra-agency workgroup to review the plan components to determine whether they conform to the applicable regulatory requirements. The workgroup may require a broad range of expertise in legal, technical, and policy areas, potentially including attorneys, engineers, scientists, economists, air monitoring experts, health and welfare analysts, and/or policy analysts from across a variety of the EPA programs. After review and coordination, the workgroup then develops recommendations for approval or disapproval of each plan component and presents them to Agency decision-makers for review. Once the Agency completes its internal decision-making process, the workgroup proceeds to prepare a written notice of proposed rulemaking. The notice of proposed rulemaking contains the EPA's legal, policy, and technical bases for its proposed action on a state plan submission, which must be thoroughly developed and explained in writing to provide clear and concise information and reasoning to support the public in understanding the Agency's decision and the justification for that decision, and so that the public may provide informed comments on the proposal. The EPA may further develop technical support documents as record support for the proposal. The draft proposed rulemaking and any record support then undergo a multi-layered review process across the EPA offices and levels of management before being processed for signature. The process to evaluate the state plan, draft a proposed action on a CAA section 111(d) state plan, and get the proposed action edited, reviewed, and signed typically requires a minimum of between 6 to 8 months to complete. The signed notice of proposed rulemaking is then submitted for publication in the **Federal Register***,* which may require several weeks of review and processing prior to publication.

The publication of the proposed rulemaking triggers the start of a public comment period of at least 30 days with possible extension, if requested by commenters. Because of the types of sources and pollutants regulated under CAA section 111(d), the EPA reasonably anticipates that many of its proposed actions on state plans will garner significant public interest from individuals, industry, states, and environmental and public health advocates. After completion of the comment period, the EPA then reviews all comments and determines whether, based on any information provided by the comments, it should alter its proposed action or further augment the legal, policy, and technical rationales

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[26] The deadlines for the EPA action under subpart Ba would apply to any state plan submission regardless of when it is submitted.

supporting that action. Comments received on a proposed action may include technical information that was not available to the EPA at the time of proposal. In the event technical data are received as part of comments on the proposed action, the EPA would then be required to review the new data and evaluate whether and how it should affect the EPA's proposed conclusions regarding the state plan. If a substantive comment is raised that merits reconsideration of the EPA's proposed action, the EPA may determine that it is necessary to revise and repropose its action on the state plan or it may go to the state for more information to help the Agency determine how to proceed.

Once this review of comments is complete, the workgroup drafts and presents updated recommendations for action for internal review and consideration by Agency decision-makers. Once the Agency completes its internal decision-making process, the workgroup then drafts a notice of final rulemaking on the plan submission, which includes responses to comments, any necessary record support, and may also include final regulatory text. The draft final action is then reviewed by senior management and other interested EPA offices within the Agency prior to signature of the final rulemaking approving or disapproving, in whole or in part, a state plan. It is reasonable to permit at least 4 to 7 months for evaluation of the comments received, any necessary technical analysis, decision-making, and drafting and review of the final action.

The duration of each step in this deliberative process varies. The amount of time the EPA needs to review a state plan submission and the time it needs to finalize a notice of proposed rulemaking depends in part on the plan's complexity and the nature of the technical, policy, and legal issues that it implicates. For example, a state plan submission that includes standards of performance for dozens of facilities on different compliance schedules would be more complex and time consuming to review than a plan that simply establishes standards of performance reflecting the presumptive level of stringency for all sources. Similarly, the amount of time needed to respond to comments and issue a final rulemaking depends in part on the number and type of comments received on the EPA's proposed rulemaking. Additionally, the EPA reasonably anticipates that it will be required to review multiple plan submissions at a given time, and these phases of review for a given plan are impacted by the EPA's review of other state plan submissions, as the EPA will need to assure its review across multiple plans and regional offices is consistent from a legal, technical, and policy perspective.

While some commenters supported 12 months as an expeditious timeframe for the EPA review and action on state plan submittals, several noted that 12 months may be insufficient. These commenters asserted that the EPA must meaningfully evaluate and take action on a state plan and a 12-month timeframe may be too short for this process. However, as detailed in the discussion above, the EPA has a mapped out the time necessary to take action on a generic plan submission and believes that 12 months is the most expeditious and therefore the most appropriate period to provide for these generally applicable implementing regulations. Additionally, the EPA has completed hundreds of actions on CAA section 110 SIPs within 12 months over the past 4 years. Given that the EPA may choose to supersede the requirements of subpart Ba as necessary in an individual EG, we believe that providing the shortest period here is consistent with considering health and welfare impacts by designing timelines to achieve state plan implementation as expeditiously as reasonably possible.

The EPA is therefore finalizing as proposed 40 CFR 60.23a(b) to provide that it will take action on a state plan or plan revision within 12 months of a determination of a complete plan pursuant to 40 CFR 60.27a(g). This is a reasonably expeditious timeframe to accommodate the EPA action on a state plan or plan revision submission and the considerations described above, while ensuring that an EG is expeditiously implemented. The process and steps described in this action highlight the fact that it would be unreasonable, if not impossible, to accomplish all of the steps in a legally and technically sound manner within a 4-month timeframe as required under subpart B. Particularly, any proposed action by the EPA has to be open for public comment for at least 30 days, and therefore the 4-month timeline provided in subpart B only gave the EPA 3 months to do the substantive work of both the proposed and final actions, including evaluating the state plan submission, drafting preamble notices, responding to comments, and developing record support at both the proposed and final action stages. A 12-month timeframe after a plan is determined to be complete more reasonably accommodates the process and steps described in this action.[27]

As explained at proposal, the EPA recognizes that the court in *ALA* faulted the Agency for failing to consider the potential impacts to public health and welfare associated with extending planning deadlines. The EPA does not interpret the court's direction to require a quantitative measure of impact, but rather consideration of the importance of the public health and welfare goals of CAA section 111(d) when determining appropriate deadlines. Because 12 months is an adequate period of time in which the EPA can both expeditiously act on a plan submission *and* ensure that its action is technically and legally sound, it follows that the EPA has appropriately considered the potential impacts to public health and welfare associated with this extension of time by providing no more time than the EPA reasonably needs to ensure a plan submission contains appropriate and protective emission reduction measures. If the EPA does not have adequate time to evaluate a state plan submission, its ability to ensure the plan contains appropriate measures to satisfactorily implement and enforce the standards necessary to comply with the EG may be compromised, which would in turn compromise the EPA's ability to ensure that the public health and welfare objectives of the EG are satisfied. Although several commenters noted that the review of some plans may require a more in depth analysis, the EPA believes 12 months is a both reasonable and expeditious timeframe to evaluate and act on most state plans. Accordingly, in order to ensure that the public health and welfare objectives of CAA section 111 are timely realized, and consistent with the direction in *ALA,* the EPA does not believe it would be appropriate to finalize a timeframe longer than 12 months for the EPA action on state plans.

4. Timeline for the EPA To Promulgate a Federal Plan

CAA section 111(d)(2) provides that the EPA has the same authority to prescribe a Federal plan for a state that fails to submit a satisfactory plan as it does for promulgating a FIP under CAA section 110(c). Accordingly, the EPA's obligation to promulgate a Federal plan is triggered in three situations: where a state does not submit a plan by the plan

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[27] While the EPA would have the discretion to act on a state's submission more quickly than 12 months where specific circumstances allow (*e.g.,* where there are no public comments on the proposed action), the EPA does not believe that it would be reasonably possible to act significantly more quickly than 12 months in most cases.

submission deadline; where the EPA determines a portion or all of a state plan submission did not meet the completeness criteria and the time period for state plan submission has elapsed and, therefore, the state is treated as having not submitted a required plan; and where the EPA disapproves a state's plan. 40 CFR 60.27a(c). The EPA is finalizing as proposed the revisions to 40 CFR 60.27a(c) providing that the Agency will promulgate a Federal plan at any time within 12 months of any of the triggers in § 60.27a(c)(1) and (2) (see section III.B. of this preamble for discussion).[28]

The EPA is obligated to promulgate a Federal plan for states that have not submitted a plan by the submission deadline. Once the obligation to promulgate a Federal plan is triggered, it can only be tolled by the EPA's approval of a state plan. If a Federal plan is promulgated, a state may still submit a plan to replace the Federal plan. A Federal plan under CAA section 111(d) is a means to ensure timely implementation of EGs, and a state may choose to accept a Federal plan for their sources rather than submit a state plan. While the EPA encourages states to timely submit plans for EGs, there are no sanctions associated with failing to timely submit an approvable plan or with the implementation of a Federal plan.[29]

The original implementing regulations in subpart B provided the EPA with 6 months to promulgate a Federal plan once its obligation to do so was triggered. 40 CFR 60.27(d). When the EPA promulgated subpart Ba in 2019, it concluded that this amount of time was insufficient and consequently extended the time for the EPA to promulgate a Federal plan to 24 months, mirroring the timeframe permitted for promulgation of a FIP under CAA section 110. 84 FR 32520, July 8, 2019. In the *ALA* decision, the D.C. Circuit vacated this revised timeline in subpart Ba on the basis that the EPA did not adequately justify the extended timeframe and did not consider the health and welfare impacts of extending the implementation timeframe.

At proposal, the EPA reevaluated the process, steps, and timeframes for the EPA to promulgate a Federal plan through a public notice-and-comment rulemaking process and proposed a 12-month timeframe to promulgate a Federal plan once its obligation to do so is triggered.[30] As explained in the notice of proposed rulemaking, a Federal plan must meet the requirements of CAA section 111(d) and therefore contain the same components as a state plan, namely standards of performance for designated facilities and measures that provide for the implementation and enforcement of such standards. CAA section 111(d)(2)(B) also explicitly requires the EPA to consider RULOF in promulgating a standard of performance under a Federal plan. Additionally, Federal plans containing standards of performance are subject to the procedural requirements of CAA section 307(d), such as the requirements for proposed rulemaking and opportunity for public hearing. CAA section 307(d)(1)(C). The EPA's regulations at 40 CFR 60.27a implement these various statutory requirements and contain general regulatory requirements for the EPA's promulgation of a Federal plan. The process, and steps for the EPA to promulgate a Federal plan consistent with these applicable requirements is described in the following paragraphs.

Once the EPA's obligation to promulgate a Federal plan is triggered, the EPA establishes an intra-agency workgroup to develop the rulemaking action to address that obligation. The workgroup first develops recommendations for the components of the Federal plan to be proposed, and on legal, policy, and technical rationales that support the recommendations. These components are identified in subpart Ba as well as in the corresponding EG and are generally the same as those required for a state plan. One of these fundamental components is the determination of standards of performance for designated facilities. Based on the requirements of CAA sections 111(d) and 111(a)(1), these standards must generally reflect the degree of emission limitation achievable through application of the BSER as determined by the EPA as part of the EG. Depending on the form of the BSER and the degree of emission limitation in a particular EG, the EPA may need to do additional work to calculate standards of performance that reflect this level of stringency. For example, an EG may translate the degree of emission limitation into a presumptive standard in the form of numerical emission rates, which a Federal plan could simply adopt as the requisite standards of performance. However, if an EG provides the degree of emission limitation in a form other than presumptive numerical standards, and the EPA may need to calculate appropriate standards of performance in the context of a Federal plan. Further, CAA section 111(d)(2) requires the EPA to consider RULOF for sources in the source category in setting standards of performance as part of a Federal plan which requires the EPA to identify whether the remaining useful lives of relevant designated facilities, among other appropriate factors, merit the EPA establishing different standards of performance for those facilities. The development of a Federal plan may also necessitate that the EPA determine appropriate testing, monitoring, reporting, and recordkeeping requirements to implement the standard if the EG does not provide presumptive requirements to address those aspects of implementation. Further, the EPA will need to consider associated compliance times for designated facilities in circumstances where they are not provided by an EG, or in cases where a standard of performance is adjusted to account for RULOF. There may also be situations where IoPs are warranted,

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[28] The EPA has discretion to address its obligation to promulgate a Federal plan in a variety of ways for states that do not have an approved state plan. For example the EPA may initially promulgate a single Federal plan that applies to all appropriate states and then update that Federal plan as necessary to accommodate the inclusion of other states that trigger the need for a Federal plan in the future (*e.g.,* a Federal plan that applies to states that fail to submit a plan can be updated to include applicability for states that later have a plan disapproved); or the EPA may promulgate separate Federal plans each time its authority to do so has been triggered (*e.g.,* the EPA will promulgate a Federal plan for all states that fail to submit a plan and another Federal plan for all states that have their plan disapproved).

[29] CAA section 179 provides that sanctions should be applied in states that fail to submit approvable SIPs for certain specified requirements for NAAQS implementation. The EPA has not promulgated any similar sanctions provisions governing the submission of state plans pursuant to section 111(d).

[30] The EPA reviewed the information available in 40 CFR part 62 associated with the promulgation of Federal Plans under CAA section 111(d). The supporting information reviewed is available at Docket ID No. EPA–HQ–OAR–2021–0527. Under the provisions of CAA section 111 and subpart B, the EPA promulgated Federal plans for municipal solid waste landfills EG 40 CFR part 60, subpart Cc (Federal plan codified at 40 CFR part 62, subpart GGG) and municipal solid waste landfills EG 40 CFR part 60, subpart Cf (Federal plan codified at 40 CFR part 62, subpart OOO).

The EPA also reviewed information available in 40 CFR part 62 associated with the promulgation of Federal Plans under CAA 129. The supporting information reviewed is available at Docket ID No. EPA–HQ–OAR–2021–0527. Under the provisions of CAA sections 111 and 129 and subpart B, the EPA has promulgated Federal plans for large municipal waste combustors EG 40 CFR part 60, subpart Cb (Federal plan codified at 40 CFR part 62, subpart FFF); small municipal waste combustors EG 40 CFR part 60, subpart BBBB (Federal plan codified at 40 CFR part 62, subpart JJJ); hospital, medical, and infectious waste incinerators EG 40 CFR part 60, subpart Ce (Federal plan codified at 40 CFR part 62, subpart HHH); commercial and industrial solid waste incinerators EG 40 CFR part 60, subpart DDDD (Federal plan codified at 40 CFR part 62, subpart III) and sewage sludge incinerators EG 40 CFR part 60, subpart MMMM (Federal plan codified at 40 CFR part 62, subpart LLL).

and the EPA will correspondingly need to identify and determine the appropriate IoPs. The development of a Federal plan with these components, or of significant revision to a Federal plan, will also include elements of meaningful engagement, as finalized in this action including revision to section 40 CFR 60.29a and as further described in section III.C. of this preamble.

Once the recommendations for each component are developed, the workgroup presents them to Agency decision-makers for review. After the Agency completes its internal decision-making process, the workgroup proceeds to prepare a written notice of proposed rulemaking. The proposal must include the following elements, as required by CAA section 307(d)(3): the factual data on which the proposed rulemaking is based; the methodology used in obtaining the data and in analyzing the data; and the major legal interpretations and policy considerations underlying the proposed rulemaking. These elements must be thoroughly developed and explained in the proposal to meaningfully provide the public adequate information to comment on the proposal. The EPA may further develop a technical support document as record support for the proposal.

The draft proposed rulemaking and any record support are then reviewed by the relevant EPA offices and processed for signature. The signed notice of proposed rulemaking is then submitted for publication in the **Federal Register**. To develop the proposed Federal plan rulemaking, establish unique standards for RULOF, allow review of materials by senior management, go through an interagency review process and have the package signed typically requires a minimum of between six to nine months to complete.

As previously noted, the EPA's promulgation of a Federal plan is subject to the requirements of CAA section 307(d), which includes providing the public with an opportunity to provide an oral presentation at a public hearing. CAA section 307(d)(5). The Federal Register Act requires the EPA to provide sufficient notice of a public hearing, which (in the absence of a different time specifically prescribed by the relevant Act of Congress) is satisfied if the EPA provides at least 15 days' notice. 44 U.S.C. 1508. Section 307(d)(5) of the CAA further provides that the EPA must keep the record for the proposed action open for public comment for 30 days after any public hearing for the submission of rebuttal and supplemental information. Because the EPA reasonably expects to provide notice of the required public hearing at the time its proposed action is published in the **Federal Register***,* in order to allow for both a 15-day notice of the public hearing and a subsequent 30-day comment period on the open record, the EPA should allow for at least 45 days for public comment on the notice of proposed action.

As with state plans, because of the types of sources and pollutants regulated under CAA section 111(d), the EPA reasonably anticipates that many of its proposed actions on a Federal plan will garner significant public interest from individuals, industry, states, and environmental and public health advocates. After completion of the comment period, the EPA then reviews all comments and determines whether, based on any comment, it should alter any components of the proposed Federal plan, or further augment the legal, policy, and technical rationales supporting that proposed action. Additionally, in the EPA's experience, comments may include technical information that was not in front of the Agency at the time of proposal. In the event technical data are received as part of comments on the proposed action, the EPA would then be required to review the new data and evaluate whether and how it should affect the EPA's proposed Federal plan. If a substantive comment is raised that merits reconsideration of any component in the proposed Federal plan, the EPA would need to repropose the plan.

Once this review of comments is complete, the workgroup drafts and presents updated recommendations for internal review and decision making. Once the Agency completes its internal decision-making process, the workgroup then drafts a notice of final rulemaking, which includes responses to comments and any necessary record support, and final regulatory text as the Federal plan directly regulates certain designated facilities. The draft final action is then reviewed by relevant offices within the Agency prior to signature of the final rule promulgating the Federal plan. The EPA typically anticipates that the process of reviewing comments received, making corresponding changes to the rulemaking, and promulgating the final Federal plan to be between 4 and 8 months.

The duration of each step in this deliberative process varies. The amount of time the EPA needs to develop, propose, and finalize a Federal plan depends in part of the plan's complexity and the nature of the technical, policy, and legal issues that it implicates. For example, some states needing a Federal plan may have thousands, if not hundreds of thousands, of designated facilities for which the EPA will need to establish standards of performance and implementation measures, while other Federal plans may be significantly smaller in scale. Similarly, the amount of time needed to respond to comments and issue a final rule depends in part on the number and type of comments received on the EPA's proposed rulemaking. Additionally, the EPA reasonably anticipates that it may need to promulgate a Federal plan for multiple states at a given time, which can amplify the amount of time and work needed.

In response to this proposed timeline, several commenters asserted that the EPA should provide itself more than the proposed 12 months to promulgate a Federal plan, with some commenters noting additional time needed for the EPA to provide for meaningful engagement and consideration of RULOF. However, based on the assessment as presented in the preceding paragraphs, recognizing that much of the evaluation needed for promulgating a Federal plan will be performed by the EPA during development of the EG, considering the need for expeditious implementation of EGs, and noting that RULOF is expected to only be needed for certain limited circumstances, the EPA is finalizing the requirement that it promulgate a Federal plan within 12 months once its obligation to do so is triggered, *i.e.,* either the date required for submission of a state plan (for states that fail to submit a complete plan) or the date the EPA disapproves a state's plan. As with the other timelines in subpart Ba, the EPA may supersede the 12 month timeline for a Federal plan as appropriate depending on the circumstances of the applicable EG.

The EPA also recognizes that some commenters stated that the EPA need not and should not wait for its Federal plan obligation to be ''triggered'' to begin developing such a plan. The EPA agrees that early development of the Federal plan, where possible before the EPA's obligation is formally triggered, could provide the EPA with additional time to meet this deadline. The EPA notes that to further streamline the timeline associated to the issuance of a Federal plan, the EPA is also finalizing the proposed change to the trigger for the EPA's obligation and timeline to provide a Federal plan for states that do not submit a timely plan. That discussion is found in section III.B. of this preamble.

Thus, the EPA is finalizing as proposed the revisions to 40 CFR 60.27a(c) providing that the Agency will promulgate a Federal plan at any time within 12 months of any of the triggers in § 60.27a(c)(1) and (2). While retaining the authority to supersede this timeline in an EG if appropriate, the EPA has determined that 12 months reasonably accommodates the amount of time that the EPA needs to undertake the process, steps, and the considerations described above, while ensuring that an EG is expeditiously implemented. The process and steps described earlier that the EPA must be taken in promulgating a Federal plan highlight the fact that it would be unreasonable, if not an impossibility, to accomplish all of the steps in a legally and technically sound manner within a 6-month timeframe as required under subpart B.[31]

As with the EPA's finalized timeline to act on state plan submissions, 12 months is generally the period of time in which the EPA can both expeditiously complete a Federal plan *and* ensure it is technically and legally sound. Therefore, this time period considers potential impacts to public health and welfare by giving the EPA a reasonably expeditious timeframe to promulgate a Federal plan that contains appropriate and protective emission reduction measures. This is especially true in the context of a Federal plan, where there is otherwise no state plan in place that is adequately protective of public health and welfare. If the EPA does not have adequate time to promulgate a Federal plan, its ability to ensure the plan contains appropriate measures to satisfactorily implement and enforce the standards necessary to comply with the EG may be compromised, which would in turn compromise the EPA's ability to ensure that the public health and welfare objectives of the EG are satisfied.

The EPA notes that a state may submit a plan to replace a Federal plan, even after the state plan submission deadline. However, once the EPA's authority and obligation to promulgate a Federal plan has been triggered, the act of a state submitting a plan alone does not abrogate the EPA's authority or obligatory timeline to promulgate a Federal plan. Only an approved state plan can supplant an already promulgated Federal plan or abrogate the EPA's responsibility to timely promulgate a Federal plan. Where a state submits a late plan, that may have the practical effect of concurrent timelines for promulgation of the Federal plan and the EPA's action on that late state plan; the EPA is not obligated to act on a late state plan prior to promulgating a Federal plan (40 CFR 60.27a(d)).

5. Timeline for Increments of Progress (IoPs)

As part of the EPA's statutory responsibility to determine the degree of emission limitation achievable through application of the BSER and to include it in an EG, the EPA also determines in an EG ''the time within which compliance with standards of performance can be achieved.'' 40 CFR 60.22a(b)(5). Accordingly, state plans must include both standards of performance for designated facilities and compliance schedules for achieving those standards of performance.[32]

In 1975, the EPA defined in subpart B ''compliance schedule'' as ''a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific standards of performance contained in a plan or with any increments of progress to achieve such compliance.'' In subpart B the EPA also defined ''increments of progress'' as steps to achieve compliance which must be taken by an owner or operator of a designated facility including: (1) submittal of a final control plan for the designated facility to the appropriate air pollution control agency; (2) awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification; (3) initiation of on-site construction or installation of emission control equipment or process change; (4) completion of on-site construction or installation of emission control equipment or process change; and (5) final compliance. The EPA adopted these definitions without change when it promulgated subpart Ba in 2019.

Subpart B requires that each state plan include emission standards and compliance schedules. 40 CFR 60.24a. In addition, subpart B specifies in 40 CFR 60.24(e)(1) that any compliance schedule extending more than 12 months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Unless otherwise specified in the applicable subpart, increments of progress must include, where practicable, each increment of progress specified in § 60.21(h) and must include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance. The provision in 40 CFR 60.24(e)(1) was amended in 2000.[33] The 2000 amendments to 40 CFR 60.24(e)(1) added the words ''Unless otherwise specified in the applicable subpart'' to the requirements associated with IoPs. The EPA described in the 1999 proposal that the purpose of this amendment was to allow the EPA, in a specific subpart, discretion in the number of IoPs that a designated facility must meet. Without this amendment subpart B required designated facilities to meet all five IoPs specified in the IoP definition. In the 1999 proposal the EPA recognized that while for some categories of designated facilities the five increments are appropriate, all five IoPs may not be necessary to ensure compliance for other categories of designated facilities. Therefore, EPA proposed and finalized amendments to 40 CFR 60.24(e) to allow discretion and flexibility in establishing IoPs for a particular subpart.

In promulgating subpart Ba in 2019, the EPA largely carried over the requirement of subpart B at 40 CFR 60.24(e)(1) in a new provision 40 CFR 60.24a(d).[34] However, to align the trigger of IoPs in 40 CFR 60.24a(d) to the updated timelines it was finalizing in subpart Ba, in 2019 the EPA adopted a timeframe trigger for IoPs of 24-months instead of the 12-months as in subpart B. Per the finalized 2019 subpart Ba provision at 40 CFR 60.24a(d), unless otherwise specified in the applicable subpart, any compliance schedule extending more than 24 months from the date required for submittal of the plan must include legally enforceable IoPs to achieve compliance for each designated facility or category of facilities. As discussed previously, the D.C. Circuit vacated the extended implementation timelines in subpart Ba, including the 24-months timeline trigger for IoPs in 40 CFR 60.24a(d).[35]

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[31] While the EPA would have the discretion to promulgate a Federal plan more quickly than 12 months where specific circumstances allow (*e.g.,* where there are no public comments on the proposed action), the EPA does not believe that would be reasonably possible to act significantly more quickly than 12 months in most cases.

[32] ''Each plan shall include standards of performance and compliance schedules.'' 40 CFR 60.24a(a).

[33] 65 FR 76380 (Dec 6, 2000).

[34] In promulgating Ba in 2019, the EPA specified that for ''For those provisions that are being carried over from the existing implementing regulations into the new implementing regulations, the EPA is not intending to substantively change those provisions from their original promulgation and continues to rely on the record under which they were promulgated.'' 84 FR 32520 (July 8, 2019).

[35] Petitioners did not challenge, and the court did not vacate in *ALA,* the substantive requirement for or definition of increments of progress.

To address the vacated timeline trigger of IoPs in 40 CFR 60.24a(d), the EPA proposed in 2022 that, unless otherwise specified in the applicable subpart, any compliance schedule extending more than 16 months from the date required for submittal of the plan must include legally enforceable IoPs to achieve compliance for each designated facility or category of facilities. The proposed 16-month trigger for IoPs overlapped with the EPA's proposed 60-day completeness review following a state plan submittal and the proposed 12-month period for the EPA to review and take action on the state's plan and would have further provided a 2-month buffer after the timeline for the EPA's action on a state plan (occurring no later than 14 months after the plan submission deadline under these general implementing regulations). In the 2022 proposal the EPA recognized the proposed 16-month timeframe trigger for IoPs provided a 2-month time buffer between the EPA's action on a state plan and the trigger of IoPs. As proposed, this 2-months buffer was less than both the 8 months previously provided by subpart B and the 6-month buffer provided by the vacated subpart Ba timeline.

In response to the proposed 16-month IoPs timeframe trigger, several commenters asserted the proposed 2-month buffer from the time of the EPA's action on a state plan to the trigger of IoPs is not practically workable. Some commenters argued that, assuming that there could be a required increment of progress right after the 16-months trigger and the EPA has 14 months to take final action on a state plan, the designated facilities would have only two months to comply with the requirement after it becomes federally enforceable. Other commenters similarly noted that if final compliance was required just after the 16-month trigger, designated facilities would similarly have only two months to complete any IoPs. The commenters explained that it is unduly burdensome for sources to expend resources on developing hypothetical final control plans and committing resources to construction projects that may ultimately be inconsistent with the EPA's action on a state plan. Several commenters that opposed the 16-months proposed timeframe trigger for IoPs suggested that the EPA extend the trigger to more than 24-months, consistent with the previously vacated subpart Ba. Some commenters argued that 24 months is the minimum time necessary to develop control strategies, design plans, procure construction materials and/or equipment, and complete the installations often necessary for compliance. Other commenters suggested that a 10-month buffer from the EPA action on a state plan to the trigger for IoPs would also be acceptable and even preferred, should the EPA miss its approval deadlines.

After consideration of comments and accounting for the discretion that EPA has in establishing IoPs in a particular EG, the EPA is extending the buffer associated with the trigger of IoPs from 2 months to 6 months, so that, unless otherwise specified in the applicable subpart, any compliance schedule extending more than 20 months from the date required for submittal of the plan must include legally enforceable IoPs to achieve compliance for each designated facility or category of facilities.

The EPA emphasizes that the timeline for the trigger for IoPs merely signals when the gap between state plan submission and final compliance is long enough that the EPA must consider whether IoPs are necessary. It is not the case that any EG with a final compliance date after the trigger for consideration of IoPs will necessarily require all of the increments listed in 40 CFR 60.21a(h). The EPA is required, per 40 CFR 60.22a(b)(4), to include within an EG ''[i]ncremental periods of time normally expected to be necessary for the design, installation, and startup of identified control systems.'' These incremental periods are determined within an EG through notice and comment rulemaking, providing an opportunity for appropriate consideration of the reasonable time needed for the designated facilities to meet the requirements associated with the pertinent standards of performance. As provided by subpart Ba, the EPA will determine in an individual EG whether IoPs are needed to achieve final compliance with the standards of performance and, if increments are needed, how many and the timeframes associated with compliance of such IoPs. However, the EPA also believes that the trigger requirement for IoPs should attach to plans that contain compliance periods that are longer than the period provided for the EPA's review of such plans and in addition provide a reasonable buffer after the EPA has acted on such plans so that designated facilities could reasonably comply with required increments. After further consideration, the EPA believes that a default 2-month buffer between an EPA action on a state plan and a hypothetical compliance deadline for a full set of IoPs is not generally sufficient.

In 2019, the EPA promulgated a trigger for IoPs of 24-months given that it was finalizing a period of up to 18 months for its action on state plans (*i.e.,* 12 months from the determination that a state plan submission is complete, which could occur up to six months after receipt of the state plan). The 24-month period would have provided a 6-month buffer for designated sources to comply with any IoPs after the EPA acted on state plans. In this action, the EPA is finalizing a trigger for consideration of IoPs that provides the same buffer provided by the EPA in the 2019 vacated increment of progress timeline trigger. The EPA believes a 6-month buffer is generally needed to appropriately balance ensuring designated facilities control emissions of harmful pollutants as expeditiously as reasonably possible with the need for designated facilities to have reasonable certainty regarding their federally enforceable regulatory compliance obligations with sufficient time before those obligations are due. In addition, the EPA determines that the 6-months buffer provides a reasonable time to come into compliance with any potential increment of progress when compliance date that extends more than 20 months from the date required for submittal of the plan. Per the EPA's assessment of the comments and in light of the *ALA* court decision, the EPA determines that a 6-month timeframe buffer before the trigger for requirements associated with IoPs provides is the most reasonable expeditious period of time associated with the requirements for IoPs in 40 CFR 60.24a(d). While some commenters argued more time is necessary to develop control strategies, design plans, procure construction materials and/or equipment, and complete the installations often necessary for compliance, the final requirements in subpart Ba does not express the EPA's intent to require that states require designated facilities to complete all potential IoPs in a 6-month period.

Several commenters also urged the EPA to link the timelines for IoPs to the date on which the EPA takes final action on a state plan, instead of with the state plan submittal deadline. However, given that there will typically be a single final compliance date specified in an EG but the dates on which the EPA takes final action on individual states plans are likely to be many and varied based on, *inter alia,* when each state plan was submitted to the Agency, such an approach would create unnecessary confusion about whether IoPs must be implemented and potentially uneven application of the requirement for state plans to include IoPs. It could also create a perverse incentive for states to delay submission of their state plans. Additionally, the timeline for IoPs initiates from the state plan submittal deadline because it is the earliest instance when all standards of performance in all timely state plans will be enforceable. It is a requirement of state plans, when submitted, to be enforceable at the state level and thus all designated facilities subject to a standard of performance in a state plan will have assurance of their requirements at the state level and can start planning for compliance while the EPA reviews and acts on the state plan.

The timeline for IoPs finalized in this action will ensure standards of performance are implemented as expeditiously as possible so that the intended emission reductions are achieved, and the public health and welfare are protected.

B. Federal Plan Authority and Timeline Upon Failure To Submit a Plan

CAA section 111(d)(2)(A) provides that the EPA has the same authority ''to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410(c) of this title in the case of failure to submit an implementation plan.'' The original implementing regulations in subpart B provide that the EPA is to ''promptly prepare and publish proposed regulations setting for a plan, or portion thereof, for a State if:'' a state fails to submit a plan within the time prescribed, the state fails to submit a plan revision within the time prescribed or the Administrator disapproves a state plan or plan revision or any portion thereof. 40 CFR 60.27(c). Subpart B further requires the EPA to promulgate the plan proposed under paragraph (c) ''within six months after the date required for submission of a plan or plan revision . . . unless, prior to such promulgation, the State has adopted and submitted a plan or plan revision which the Administrator determines to be approvable.'' 40 CFR 60.27(d).

In promulgating subpart Ba in 2019, the EPA incorporated language in the provisions associated with the Actions by the Administrator in 40 CFR 60.27a(c) from CAA sections 110(c)(1)(A) and 110(k)(1)(B) addressing the circumstances which trigger the EPA's authority under CAA section 111(d)(2) for promulgating a Federal plan. Specifically, in 2019 the EPA adopted language at 40 CFR 60.27a(c)(1) that requires the EPA to promulgate a Federal plan after it ''*[f]inds* that a state fails to submit a required plan or plan revision or *finds* that the plan or plan revision does not satisfy the minimum criteria under'' 40 CFR 60.27a(g), *i.e.,* the completeness criteria (emphasis added). Pursuant to the amendments being finalized in this action, the EPA will be required, under 40 CFR 60.27a(g), to determine whether completeness criteria have been met no later than 60 days after the date by which a state is required to submit a plan (see section III.A.2. of this preamble). These provisions under subpart Ba taken together would mean that, no later than 60 days after the state plan submission deadline has passed, the EPA must make a finding (often referred to as a ''finding of failure to submit'') as to whether any states have failed to submit a plan that meets the completeness criteria, and such finding is what triggers the EPA's obligation and timeline to promulgate a Federal plan.[36]

At proposal, the EPA acknowledged that in the CAA section 110 context, it has not always timely met its obligation to issue a finding of failure to submit, which in turn delays the timing for when the EPA promulgates a FIP to achieve the necessary emission reductions. Accordingly, the EPA proposed to streamline the process in the subpart Ba context to ensure that the emission reductions anticipated by the EG are realized in a timely way through the promulgation of any necessary Federal plan. In particular, the EPA proposed revisions to 40 CFR 60.27a(c)(1) consistent with the framework and requirements that have been effective in subpart B since 1975. As proposed the Administrator would issue a Federal plan if a state fails to submit a plan within the time prescribed without requiring the EPA to affirmatively issue a finding of failure to submit before the EPA's obligation to issue a Federal plan is triggered.

As explained in the notice of proposed rulemaking, as part of evaluating ways to streamline the steps leading to promulgation of a final Federal plan, the EPA considered the value and role of issuing findings of failure to submit in this process. A finding of failure to submit was intended to serve three purposes under subpart Ba, consistent with its purpose under CAA section 110: to notify the public of the status of state plan submissions (*i.e.,* providing transparency to the process); to notify states that the EPA has not received a plan; and to formally start the clock for the EPA to promulgate a Federal plan. While these concepts may have some utility as part of the overall Federal plan development and implementation process, the EPA finds that in the CAA section 111(d) context there is minimal value in coupling the notification aspects of a finding of failure with the initiation of the clock for the EPA to promulgate a Federal plan. These aspects are not inextricably linked to one another in that nothing about a formal finding of failure to submit substantively informs the development of a Federal plan; the EPA has the information it needs to know which states have and have not submitted complete plans. By decoupling the timeline from the finding of failure to submit, the EPA's obligation to promulgate a Federal plan can be triggered without the interim step and potential lag associated with issuing a formal finding of failure to submit notification. By removing this interim process, the EPA will be required to promulgate the Federal plan more expeditiously, and, in turn, overall implementation of the corresponding EG will be timelier. Finalizing this amendment is also consistent with the spirit of the *ALA* decision, where the D.C. Circuit emphasized the need for implementation timelines that consider potential impacts on public health and welfare. By expeditiously and efficiently promulgating a Federal plan and by removing an interim step of a finding of failure, the EPA is further addressing the potential impacts of implementation times on health and welfare.

Some commenters requested that the EPA retain a separate ''finding of failure to submit'' action as the trigger for starting the timeline on a Federal plan. They note that the ''finding of failure'' provides notification to the states, regulated community, and public of the failure, as state submissions can be difficult to track. Commenters also note that the need to first provide the finding also provides additional time for the states to submit plans or revisions. One commenter noted that the EPA should retain the ''finding of failure to submit'' procedure and avoid establishing automatic deadlines for itself on a schedule that, based on past experience, it is almost certain to miss.

First, the EPA notes that where a state has failed to timely submit a state plan, the absence of a state plan submission should be easy to track for the state,

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[36] Note that this procedure does not address circumstances when the EPA promulgates a Federal plan for states whose plan is disapproved. In these circumstances, the state has submitted a plan so no finding of failure to submit is issued. The EPA's obligation and timeline to promulgate a Federal plan in this instance arises from the EPA's disapproval based on its conclusion that the state plan submission was unsatisfactory.

regulated community, and public; many, if not all, states maintain public websites on which they document their submissions to the EPA. The EPA expects that notification and tracking capabilities will also generally be much improved through the use of electronic submittal (see section III.F. of this preamble) and increasing public access to online information.

Second, the EPA stresses that the purpose of using a finding of failure to submit as the trigger for Federal plan development was not to give states time to develop and submit their state plans in excess of the regulatorily allotted timeframes. In this action, the Agency is finalizing timeframes for state plan submissions that are reasonably achievable and that may be superseded where necessary. Decoupling the finding of failure to submit and the trigger of state plan development should therefore not impact states' abilities to develop and submit satisfactory state plans. States always have the ability to submit state plans and state plan revisions at any time. Additionally, while the EPA recognizes that it has not always provided timely Federal plans, the Agency does not believe that changing the starting point for its Federal plan clock from a finding of failure to submit to the day after state plan submission are due will have an appreciable impact on its ability to do so. Notably, the trigger for its timeline will not change the length of time the EPA has to promulgate a plan. While the commenter implies that the EPA would use the time before it has made a finding of failure to submit to start working on a Federal plan, it is not reasonable to assume that the Agency is in a position to start developing such a plan before it has had a chance to determine if a state plan is incomplete. Therefore, the EPA is finalizing its proposed approach of removing from subpart Ba a finding of failure to submit as the trigger for starting the timeline for a Federal plan. The approach being finalized in subpart Ba is consistent with the framework and requirements that have been effective in subpart B since 1975. The regulatory text at 40 CFR 60.27a(c)(1) is being revised slightly relative to proposal to clarify that the 12-month clock starts running the day after the state plan submission deadline for instances in which a state fails to submit a plan or plan revision by that deadline, and the day after state plan submissions would be deemed complete by operation of law (*i.e.,* 60 days after the state plan submission deadline) for instances in which a state plan has been submitted but deemed incomplete.[37] These revisions merely clarify the EPA's intent at proposal to ensure that all states and stakeholders have a clear understanding of the timeline for promulgation of a Federal plan. As discussed in section III.A.4. of this preamble, the EPA is finalizing the requirement that it will have 12 months from the state plan deadline to promulgate a Federal plan for states that do not submit a plan. Note, the EPA is also finalizing a deadline of 12 months to promulgate a Federal plan for states whose plans are disapproved, but in those instances the EPA's obligation and timeline to provide a Federal plan are triggered off of its disapproval of a state plan.

The EPA notes that this amendment to subpart Ba does not affect the EPA's obligation under CAA section 110(c) to promulgate a FIP within 2 years of making a finding that a state has failed to submit a complete SIP. In the case of the CAA section 110, the obligation for the EPA to first make a finding of failure to submit is derived from the statute, whereas nothing in CAA section 111(d) obligates the EPA to make such a finding before promulgating a Federal plan. CAA section 111(d)(1) directs the EPA to promulgate a process ''similar'' to that of CAA section 110, rather than a process that is identical. Therefore, the fact that a finding of failure to submit serves as the legal predicate for the EPA's obligation to issue a FIP under CAA section 110 does not mean that the EPA is also required to treat such a finding as a legal predicate for a Federal plan under CAA section 111(d).

In summary, while recognizing that a finding of failure to submit can have value in notifying states and the public of the status of plans, the EPA does not find that it is integral to the process of promulgating a Federal plan for states that do not submit plans. Further, the requirement for the EPA to issue a finding of failure can result in significant unwarranted delays in EG implementation. The EPA is therefore finalizing the proposed amendment that this finding will no longer be the event that triggers the timeline for the EPA's issuance of a Federal plan. 40 CFR 60.27a(c)(1). While the EPA will not publish a formal finding of failure to submit in the **Federal Register**, the Agency will notify the states and the public of a failure to submit expeditiously following the state plan submission deadline or deadline for EPA determinations of completeness, as applicable. Additionally, the EPA notes that the completeness criteria in 40 CFR 60.27a(g) were promulgated in 2019, 84 FR 32520, 32578 (July 8, 2019), and, while the EPA is removing finding of failure to submit as the trigger for promulgation of a Federal rule, it emphasizes that states may have discussions with the EPA and submit revised state plans at any point. That is, there remains within this framework ample opportunity for iterative state plan development.

The regulatory provision at 40 CFR 60.27a(c)(1), as finalized, is consistent with the requirement that applies regarding the EPA's issuance of a Federal plan under subpart B. In subpart B (*i.e.,* applicable to implementing regulations for CAA section 111(d) EGs promulgated on or prior to July 8, 2019, and currently applicable implementing regulations for CAA section 129 EGs), the EPA's obligation to promulgate a Federal plan is triggered by the state plan submission deadline.

C. Outreach and Meaningful Engagement

The fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause or significantly contribute to air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, a key consideration in the state's development of a state plan, in any significant plan revision,[38] and in the EPA's development of a Federal plan or significant plan revision, pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare. A robust and meaningful public participation process is critical to ensuring that the full range of these impacts are understood and considered.

States often rely primarily on public hearings as the foundation of their public engagement in their state plan development process because a public hearing has always been explicitly required pursuant to the applicable regulations. The existing provisions in subpart Ba (40 CFR 60.23a(c) through (f)) detail the public participation requirements associated with the development of a state plan. Per these implementing regulations, states must

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[37] As discussed in section III.A.2., if a state submits a plan but that submission does not contain the elements required by the completeness criteria, the EPA would find that the state has failed to submit a complete plan and notify the state through a letter. That letter is for notification only and, although the EPA intends to issue such letters expeditiously, it does not start the clock for a Federal plan.

[38] A significant state plan revision includes, but is not limited to, any revision to standards of performance or to measures that provide for the implementation or enforcement of such standards.

provide certain notice of, and conduct one or more public hearings on, their state plan before such plan is adopted and submitted to the EPA for review and action.[39] The EPA is not reopening these basic and long-standing public hearing requirements in this rulemaking. However, as explained in the notice of proposed rulemaking,[40] robust and meaningful public involvement in the development of a plan should sometimes go beyond the minimum requirement to hold a public hearing depending on who may be most affected by and vulnerable to the impacts being addressed by the plan. Because the CAA section 111(d) program addresses existing facilities, some of which may be decades old, it is possible that impacted communities may not have had a voice in the process when the source was originally constructed, or previous outreach may have focused largely on engaging the industry. The EPA proposed amendments to 40 CFR part 60, subpart Ba, were intended to strengthen the public participation provisions and ensure that all affected members of the public, not just a particular subset, have an opportunity to participate in the pollution control planning process by requiring meaningful engagement with pertinent stakeholders in the state's development of a state plan, in any significant plan revision, and in the EPA's development of a Federal plan pursuant to an EG promulgated under CAA section 111(d).

The EPA proposed to add meaningful engagement with pertinent stakeholders in 40 CFR 60.23a(i) and 60.27a(f) and add the definition of meaningful engagement and of pertinent stakeholders in 40 CFR 60.21a. The EPA proposed to define meaningful engagement as it applies to this subpart as timely engagement with pertinent stakeholder representation in the plan development or plan revision process. Such engagement must not be disproportionate nor favor certain stakeholders. It must include the development of public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to participation to assure pertinent stakeholder representation, recognizing that diverse constituencies may be present within any particular stakeholder community. It must include early outreach, sharing information, and soliciting input on the state plan. The EPA also proposed to evaluate the approvability of state plans based on the components of the meaningful engagement definition.

The EPA proposed that pertinent stakeholders ''. . . include, but are not limited to, industry, small businesses, and communities most affected by and vulnerable to the impacts of the plan or plan revision.'' Additionally, to ensure that a robust and meaningful public engagement process occurs as the states develop their CAA section 111(d) plans, the EPA proposed to amend the requirements in 40 CFR 60.27a(g) to include, as part of the completeness criteria, the requirement for states to demonstrate in their plan submittal how they provided meaningful engagement with the pertinent stakeholders. The state would be required to provide, in their plan submittal: (1) a list of the pertinent stakeholders identified by the state; (2) a summary of engagement conducted; and (3) a summary of the stakeholder input received.

Most of the comments received on the proposed meaningful engagement requirements and proposed definitions were supportive of including meaningful engagement in the development of the state plans. Several commenters stated that they supported the inclusion of environmental justice considerations in Federal programs, including requirements for meaningful engagement. In particular, one commenter stated that outreach and meaningful engagement with stakeholders, specifically including communities most affected by and vulnerable to the pollution that would be reduced by a state plan, is an important and overdue step to ensuring that impacted communities have a voice in a process that directly impacts their health and welfare. While several commentors affirmed the EPA's authority to require meaningful engagement, some commenters said that the EPA lacks such authority. One of the commenters argued that the EPA lacks authority to require consideration of public health and welfare under CAA section 111(d) because CAA section 111 was devised as a technology-based approach to controlling emissions from stationary sources, not one predicated on the setting of standards directly and exclusively based on public health and welfare needs. One of the commenters stated the EPA lacks the authority to pass judgment on state plans submitted pursuant to CAA section 111(d) based on public engagement and argued that the only statutory requirement in CAA section 110 (which 111(d) cross-references) is the requirement that states provide ''reasonable notice and public hearings'' prior to adoption of a state plan.

Several commenters supported the EPA's definition of meaningful engagement and the proposed meaningful engagement requirement. Additionally, some comments supported the state plan approvability requirements for meaningful engagement and recommended that the EPA also require an accounting of what states have done with stakeholder input and how that input was used or not used in their state plan.

Several commenters expressed the need for additional resources in order to conduct meaningful engagement, both for states and communities. Some of the comments stated that the EPA needs to consider how these increased requirements may strain already limited state resources. One commenter said that resources needed to fulfill the requirements for meaningful engagement, including costs associated with identifying and contacting stakeholders, renting of rooms or spaces for multiple public meetings, travel, and associated staff time, will be significant and burdensome to states.

There were several comments requesting clarification on the definition of meaningful engagement, and on the proposed approvability requirements for meaningful engagement. Some commenters requested that the rule provide more clarity on what states need to do for meaningful engagement and provide a clear path for states to develop an approvable meaningful engagement demonstration. Similarly, other commenters recommended the EPA establish a more detailed definition and provide examples of best practices for states to follow in implementing meaningful engagement, particularly with vulnerable communities, and further clarify what is meant by meaningful engagement with pertinent stakeholders. Some commenters cited lack of clarity in expressing their concern with meaningful engagement being a requirement for state plan approvability.

Based on comments received, the EPA has revised the proposed definition of meaningful engagement and is finalizing revisions that are flexible enough to serve the unique needs of states and their stakeholders, rather than relying on the more prescriptive approach of the proposal. The EPA recognizes that states will generally be in the best position to understand how to meaningfully engage pertinent stakeholders within their borders as they develop state plans. The EPA also believes that states and the Federal Government may learn from each

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[39] States may cancel a public hearing if no request for one is received during the required notification period. 40 CFR 60.23a(e).

[40] 87 FR 79176, 79190–92 (Dec. 23, 2022).

other's efforts to meaningfully engage pertinent stakeholders. The EPA further recognizes that appropriate approaches to meaningful engagement, as well as the time and resources needed, will be highly dependent on characteristics of the source category—such as the number and location of designated facilities—as well as on the type of health or environmental impacts of the emissions addressed by an EG. Additionally, as noted by a number of commenters, states are highly diverse in, among other things, their local conditions, resources, and established practices of engagement. Also as noted by commenters, vulnerable communities are highly diverse in, among other things, their technical capacities, access to resources for meaningful participation (*e.g.,* geographic distribution, transportation, childcare), languages, and available representation.

For these reasons, rather than finalizing prescriptive substantive requirements for how states should conduct meaningful engagement, the EPA is requiring in subpart Ba that states, in their state plan submissions or significant plan revisions, describe the efforts they undertook to meaningfully engage pertinent stakeholders, what input they received from stakeholders, and how that input was used or not used in their state plan. The EPA will also include this information when promulgating Federal plans or significant plan revisions. In addition, the EPA is describing some current best practices for meaningful engagement in this preamble that states may consider, that and which the Agency expects will continue to develop as states experiment with different types of meaningful engagement and share their experiences through state plans.

Consistent with these changes, the EPA is finalizing the definition of meaningful engagement, as it applies to subpart Ba, as follows: ''. . . timely engagement with pertinent stakeholders and/or their representatives in the plan development or plan revision process. Such engagement should not be disproportionate in favor of certain stakeholders and should be informed by available best practices.'' States should therefore make a good faith effort to ensure that they are engaging in a proportionate manner with all pertinent stakeholders. The EPA is also finalizing, as proposed, a definition of ''pertinent stakeholders.'' Pertinent stakeholders ''include, but are not limited to, industry, small business, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision.'' Finally, the EPA is including in subpart Ba the three proposed completeness criteria requirements for meaningful engagement at 40 CFR 60.27a(g)(2)(ix) and adding a fourth completeness criterion, which will require state to include in their plans a description of how stakeholder input was considered in the development of the state plan or plan revisions.

The EPA expects that the finalized approach to meaningful engagement in state plans will provide the flexibility needed to allow states to address specific and unique issues in their states and to appropriately communicate with and respond to their stakeholders during the notice and comment process. As revised, the meaningful engagement component finalized here strengthens the framework for public participation in state plan development, a long-standing cornerstone of the cooperative federalism structures of CAA sections 110 and 111(d). The meaningful engagement component finalized here is intended to promote equitable opportunities to participate in the planning process for all stakeholders, as opposed to dictating a specific approach or set of practices that constitute meaningful engagement.

To support the goals outlined above, and in response to comments received, the EPA is finalizing the proposed completeness criteria that require documentation of meaningful engagement, including adding a fourth completeness criterion, but the EPA is not finalizing specific requirements for what types of outreach meaningful engagement must include in subpart Ba. The fourth completeness criterion will require states to include a description of how stakeholder input from the meaningful engagement process was considered in the development of the plan, which the EPA expects will both bolster accountability to stakeholders and assist states in ensuring that their meaningful engagement processes are additive to the public hearing and notification processes which has always been required under subpart Ba. See 40 CFR 60.27a(g)(1)(ix). While the EPA finds that the requirements finalized in this action are sufficient and appropriate for the general CAA section 111(d) implementing regulations, the EPA may provide additional guidance pertaining to meaningful engagement in specific EGs.

While the EPA is revising the definition of meaningful engagement relative to proposal, the definition of pertinent stakeholders is being finalized as proposed. Pertinent stakeholders include, among other stakeholders, industry, small business, and communities—in particular, communities who are most affected by and vulnerable to the health or environmental impacts of pollution from the designated facilities addressed by the plan or plan revision. Increased vulnerability of communities may be attributable to, among other reasons, an accumulation of negative environmental, health, economic, or social conditions within these populations or communities, and a lack of positive conditions. Examples of such communities have historically included, but are not limited to, communities of color (often referred to as ''minority'' communities), low-income communities, Tribal and indigenous populations, and communities in the United States that potentially experience disproportionate health or environmental harms and risks as a result of greater vulnerability and/or exposure to environmental hazards. For example, populations lacking the resources and representation to combat the effects of climate change—which could include populations exposed to greater drought or flooding, or damaged crops, food, and water supplies—experience greater vulnerability to environmental hazards. Sensitive populations (*e.g.,* infants and children, pregnant women, the elderly, and individuals with disabilities exacerbated by environmental hazards) may also be most affected by and vulnerable to the impacts of the plan or plan revision depending on the pollutants or other factors addressed by an EG.

Communities in neighboring states or neighboring Tribal nations may also be impacted by a state plan and, if so, are pertinent stakeholders. In addition, to the extent a designated facility would qualify for a less stringent standard through consideration of RULOF as described in section III.E. of this preamble, the pertinent stakeholders would include the communities most affected by and vulnerable to the health and environmental impacts from the designated facility considered in a state plan for RULOF provisions.

The EPA has determined that the definitions of meaningful engagement and pertinent stakeholders in subpart Ba provide the states sufficient specificity while allowing for flexibility in the implementation of meaningful engagement. Meaningful engagement is an enhancement of the existing public notice and comment requirements and is intended to promote the sharing of relevant information with, and the soliciting of input from, pertinent stakeholders at critical junctures during plan development. In particular, the processes for meaningful engagement should allow for fair and balanced participation, including opportunities for communities most affected by and vulnerable to the impacts of a plan an opportunity to be informed of and weigh in on that plan. These procedural requirements, in turn, help ensure that a plan will adequately address the potential impacts to public health and welfare that are the core concern of CAA section 111. Meaningful engagement can provide valuable information regarding health and welfare impacts experienced by the public (*e.g.,* recurring respiratory illness, missed work or school days due to illness associated with pollution, and other impacts) and allow regulatory authorities to explore additional options to improve public health and welfare. Because the CAA section 111(d) program is designed to address widely varying types of air pollutants that may have very different types of impacts, from highly localized to regional or global, what constitutes fair and balanced participation among a broad set of pertinent stakeholders will be highly dependent on which stakeholders are directly impacted by a particular state plan.

The EPA's authority for finalizing procedural requirements to strengthen the public participation provisions of the implementing regulations is provided by the authority of both CAA sections 111(d) and 301(a)(1). Under CAA section 111(d), one of the EPA's obligations is to ''establish a procedure similar to that provided by'' CAA section 110, under which states submit plans that implement emission reductions consistent with the BSER. CAA section 110(a)(1) requires states to adopt and submit SIPs after ''reasonable notice and public hearings.''[41] The Act does not define what constitutes ''reasonable notice and public hearings'' under CAA section 110, and the EPA has reasonably interpreted this requirement in promulgating a process under which states submit state plans.[42]

Subpart Ba currently includes certain requirements for notice and public hearing in 40 CFR 60.23a(c) through (f). The notice requirements include prominent advertisement to the public of the date, time, and place of the public hearing, 30 days prior to the date of such hearing, and the advertisement requirement may be satisfied through publication to the internet. *Id.* at paragraph (d). A state may choose to cancel a public hearing if no request for one is received during the required notification period. *Id.* at paragraph (e).

A fundamental purpose of the Act's notice and public hearing requirements is to ensure that all affected members of the public are able to participate in pollution control planning processes that impact their health and welfare.[43] In order to effectuate this purpose of the Act's notice and public hearing requirements, the notice of the proposed plans and of the public hearings should be reasonably adequate in its ability to reach affected members of the public. While many states provide for notification of public engagement through the internet consistent with the current requirements under the CAA section 111(d) implementing regulations, such notification may not be adequate to reach all those who are impacted by a CAA section 111(d) state plan and would benefit the most from participating in the state planning process. For example, data shows that as many as 30 million Americans do not have access to broadband infrastructure that delivers even minimally sufficient speeds, and that 25 percent of adults ages 65 and older report never going online.[44] Accordingly, the EPA has determined that it is appropriate to improve the procedural public engagement requirements under CAA section 111(d) to ensure the statutory objectives are met.

Given the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, it is reasonable to include a meaningful engagement component as part of the state plan development public participation process in order to further these objectives. Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations ''as are necessary to carry out [its] functions under [the CAA].'' As finalized, the meaningful engagement components of this rule would effectuate the EPA's function under CAA section 111(d) in prescribing a process under which states submit plans to implement the statutory directives of this section and promote the statutory objective that all pertinent stakeholders have reasonable notice of relevant information and the opportunity to participate in the state plan development throughout the process. Ongoing engagement between states and pertinent stakeholders will help ensure that plans achieve the appropriate level of emission reductions, that communities most affected by and vulnerable to the health and environmental impacts from the designated facilities share in the benefits of the state plan, and that these communities are protected from being adversely impacted by the plan.

To promote meaningful engagement, the EPA is finalizing as part of the completeness criteria in 40 CFR 60.27a(g) procedural requirements for states to describe in their plan submittals how they engaged with pertinent stakeholders. As proposed, the state will be required to describe, in its plan submittal, (1) a list of the pertinent stakeholders identified by the state; (2) a summary of engagement conducted; and (3) a summary of the stakeholder input received. The EPA is also finalizing a fourth component as part of the procedural completeness demonstration—that the state also includes (4) a description of how stakeholder input was considered in the development of the plan or plan revisions. The EPA will review the state plan to ensure it includes these required descriptions regarding meaningful public engagement as part of its completeness evaluation of a state plan submittal. If a state plan submission does not include the required elements for notice and opportunity for public participation, including the procedural requirements at 40 CFR 60.23a(i) and 60.27a(g)(2)(ix) for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or (where a plan has become complete by operation of law) to disapprove the plan.

While the EPA is finalizing procedural requirements for meaningful engagement as completeness criteria and is not prescribing how states proceed with such engagement, we understand states would find it useful to consider guidance as to how such engagement could be meaningfully conducted. In light of this interest, the following paragraphs provide examples and guidance which the EPA

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[41] 42 U.S.C. 7410(a)(1).

[42] See 40 CFR 51.102; 40 CFR part 51, appendix V, section 2.1.

[43] Consistent with this principle of providing reasonable notice under the CAA, under programs other than CAA section 111(d), current regulations governing other CAA programs similarly require states to provide specific notice to an area affected by a particular proposed action. See *e.g.,* 40 CFR 51.161(b)(1) (requiring specific notice for an area affected by a state or local agency's analysis of the effect on air quality in the context of the New Source Review program (40 CFR 51.102(d)(2), (4), and (5) (requiring specific notice for an area affected by a CAA section 110 SIP submission).

[44] FACT SHEET: Biden-Harris Administration Mobilizes Resources to Connect Tribal Nations to Reliable, High-Speed Internet (December 22, 2021). *https://www.whitehouse.gov/briefing-room/statements-releases/2021/12/22/fact-sheet-biden-harris-administration-mobilizes-resources-to-connect-tribal-nations-to-reliable-high-speed-internet/;* 7 percent of Americans don't use the internet. Who are they? Pew Research Center (April 2, 2021), *https://www.pewresearch.org/fact-tank/2021/04/02/7-of-americans-dont-use-the-internet-who-are-they/.*

encourages states to consider in designing their own meaningful engagement programs.

In considering approaches for meaningful engagement, states should consider the identification of pertinent stakeholders; developing a strategy for engagement with the identified pertinent stakeholders; making information available in a transparent manner; and providing adequate and accessible notice. First, it would be reasonable for states to identify pertinent stakeholders considering information specific to the applicable EG, including the nature of the designated pollutants at issue and the communities likely to be impacted by facilities in the source category. The EPA intends to specifically provide information on impacts of designated pollutant emissions to assist states in the identification of their pertinent stakeholders, in addition to any other guidance that EPA may find it reasonable to provide in the applicable EG. Moreover, in developing a strategy for engagement, it would be reasonable for states to share information and solicit input on plan development and on any accompanying assessments. Finally, in providing transparent and adequate notice of plan development, states should consider that internet notice alone may not be adequate for all stakeholders, given lack of access to broadband infrastructure in many communities. Thus, in addition to internet notice, examples of prominent advertisement for engagement and public hearing may include notice through newspapers, libraries, schools, hospitals, travel centers, community centers, places of worship, gas stations, convenience stores, casinos, smoke shops, Tribal Assistance for Needy Families offices, Indian Health Services, clinics, and/or other community health and social services as appropriate for the emission guideline addressed.

The EPA believes the following example, while not tailored to specific designated facilities but to a source category for recent EG development, provides states with ideas for how they can structure their own meaningful engagement activities.[45] Prior to the November 2021 proposal for the ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review'' (86 FR 63110), the EPA conducted meaningful engagement with pertinent stakeholders. For the pre-proposal stakeholder outreach, the EPA engaged with stakeholders through information posted on the internet, meetings, training webinars, and public listening sessions to disseminate information regarding this action, communicate how to submit comments on the proposed rule, and receive stakeholder input about the industry and its impact. In addition to the pre-proposal stakeholder engagement, the EPA conducted additional post-proposal training during the comment period on the proposed rule and held a public hearing. The EPA conducted three half-day post-proposal trainings to provide background information, an overview of the proposed rule, stakeholder panel discussions, and information on how to effectively engage in the regulatory process. The trainings were open to the public, focusing on individuals from and representatives of communities with EJ concerns, Tribes, and small businesses. Further considerations, analyses, and outreach relevant to meaningful engagement are presented in sections VI.[46] and VII.[47] of the preamble for that action and could help states in designing, planning, and developing their own outreach and engagement plans associated with the development and implementation of their state plans. An additional resource is the memorandum on stakeholder outreach [48] for the ''New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule'' proposed rule (88 FR 33240, May 23, 2023). This memorandum provides states with another example of the types of activities and processes that the EPA has found appropriate for meaningfully engaging with stakeholders in the particular context of EG development.

The EPA recognizes that the state planning process is different than a national rulemaking and may benefit from different types of engagement. Nonetheless, the information and examples the EPA has provided on meaningful engagement can serve as an example of what types of engagement states should consider for their meaningful engagement processes. In addition, to further assist states in the meaningful engagement efforts, the EPA expects to develop resources to aid states in establishing meaningful engagement best practices, while recognizing that states have differing situations and that best practices will not be ''one size fits all.'' One resource that states may find helpful in developing their own best practices is the ''Public Involvement Policy of the US Environmental Protection Agency,'' [49] which is currently under revision. Another helpful resource the EPA has developed is the ''Capacity Building Through Effective Meaningful Engagement'' booklet.[50] The booklet is also available in the docket for this rule. Additionally, most states have opted into the EPA Climate Pollution Reduction Grant Program (CPRG),[51] developed under the Inflation Reduction Act.[52] To assist states that are participating in the CPRG, the EPA is conducting training for states on meaningful engagement, sharing case studies, best practices, and lessons learned through ongoing EPA-led CPRG forums. The EPA expects that, with experience and shared access to information on best practices, approaches to address challenges and barriers, and other resources and collaborative opportunities, meaningful engagement practices at the state and Federal level will continue to improve.

D. Regulatory Mechanisms for State Plan Implementation

CAA section 111(d)(1) requires the EPA to promulgate regulations that establish a procedure ''similar'' to that provided by CAA section 110 for each state to ''submit to [the EPA] a state plan which . . . establishes standards of performance . . . and . . . provides for the implementation and enforcement of such standards.'' The EPA reasonably interprets this provision, particularly

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[45] The EPA emphasizes that the appropriateness of any meaningful engagement strategy will depend on the specific context, including the sources and pollutants addressed by the EG, the scope and scale of the proposed regulation or plan, and the pertinent stakeholders. The activities and processes included in the examples of meaningful engagement in this preamble were tailored to the specific circumstances of EPA's EG development.

[46] See 86 FR 63110, 63140.

[47] See 86 FR 63110, 63145.

[48] See Docket ID No. EPA–HQ–OAR–2023–0072–0002.

[49] *https://archive.epa.gov/publicinvolvement/web/pdf/policy2003.pdf.*

[50] *https://www.epa.gov/system/files/documents/2023-09/epa-capacity-building-through-effective-meaningful-engagement-booklet_0.pdf.*

[51] See U.S. EPA Office of Air and Radiation ''Climate Pollution Reduction Grants Program: Formula Grants for Planning Program Guidance for States, Municipalities, and Air Pollution Control Agencies'' (March 1, 2023), *https://www.epa.gov/system/files/documents/2023-02/EPA%20CPRG%20Planning%20Grants%20Program%20Guidance%20for%20States-Municipalities-Air%20Agencies%2003-01-2023.pdf* (overview of the CPRG). See also U.S. EPA, ''Status of Notice of Intent to Participate (NOIP) Submittals by States (March 31, 2023), *https://www.epa.gov/system/files/documents/2023-04/NOIP%20Status%20Lists.pdf* (list of states who have opted in to the CPRG as of March 31, 2023).

[52] Inflation Reduction Act section 60114.

the ''similar'' clause, as referring to all the procedural provisions provided in CAA section 110 which serve the same purposes of providing useful flexibilities for states and EPA actions that help ensure emission reductions are appropriately and timely implemented.

The EPA proposed to incorporate 5 regulatory mechanisms as amendments to the implementing regulations under 40 CFR part 60, subpart Ba, governing the processes under which states submit plans and the EPA acts on those plans. 87 FR 79176, 79193–96 (Dec. 23, 2022). The proposed additional regulatory mechanisms include: (1) partial approval and disapproval of state plans by the EPA; (2) conditional approval of state plans by the EPA; (3) parallel processing of plans by the EPA and states; (4) a mechanism that allows the EPA to call for revision of a previously approved state plan; and (5) an error correction mechanism for the EPA to revise its prior action on a state plan.[53] These mechanisms were proposed to update the implementing regulations to better align with the flexible procedural tools that Congress added into section 110 of the CAA in the 1990 Amendments. The EPA is finalizing the adoption and incorporation of these mechanisms into subpart Ba as the EPA has interpreted and applied them in the context of CAA section 110.

As explained in the notice of proposed rulemaking, the interpretation that CAA section 111(d)(1) authorizes the EPA to adopt procedures ''similar'' to those under CAA section 110 for the entire state plan process, and not just the initial plan submission process, is strengthened by the provisions in CAA section 111(d)(2), which provide that the EPA has the ''same'' authority to promulgate a Federal plan for a state that has failed to submit a satisfactory plan as under CAA section 110(c), and to enforce state plan requirements as it does for SIPs under CAA sections 113 and 114. This is because, read together, CAA section 111(d)(1) and (2) call for the set of essential procedural requirements for state and Federal plan development and implementation and enforcement that generally reflect the essential procedural requirements for SIPs and FIPs in section 110.[54] In that context, it is reasonable to read CAA section 111(d)(1) as authorizing the EPA to promulgate procedures for section 111(d) that are comparable to CAA section 110 procedures for the overall state plan process. Moreover, the EPA believes that it is reasonable, in promulgating the regulations required under CAA section 111(d)(1), to look to the mechanisms and flexibilities that Congress has deemed appropriate for states and the EPA to use in the highly analogous context of state and Federal implementation plans.

The availability of these 5 regulatory mechanisms will streamline the state plan review and approval process, accommodate variable state processes, facilitate cooperative federalism, further protect public health and welfare, and generally enhance the implementation of the CAA section 111(d) program. Together, these mechanisms provide greater flexibility, may reduce processing time, and have proven to be very useful tools for the review and processing of CAA section 110 SIPs.

Overall, the comments received for incorporating the 5 regulatory mechanisms were favorable, in particular noting that the mechanisms would offer not only procedural improvements long sought by state agencies but also reflect the flexibility offered in section 111 of the CAA, consistent with the Act's cooperative approach, and would expand state planning options while conserving state resources. However, one commenter noted generally that for 111(d) plans, the CAA directs the EPA to establish a procedure similar to CAA section 110 for SIP submittals but does not require those procedures to be identical. This commenter contended that while the CAA specifically authorized various flexible mechanisms in sections 110(k)(2)–(6), the plain language of CAA section 111 does not provide for these options for 111(d) plans.

The EPA agrees that procedures adopted under CAA section 111(d)(1) need not be identical to CAA section 110 procedures, but interprets section 111(d)(1) to authorize the EPA to adopt procedures under 111(d)(1) which are substantially the same as those outlined under section 110, including section 110 procedural mechanisms.[55] Additionally, as explained above, while CAA section 111(d)(1) directs EPA to establish ''a procedure . . . under which each State shall submit to the Administrator a plan,'' section 111(d)(2) further provides that EPA also has authority to prescribe a Federal plan where states fail to submit a satisfactory plan and to enforce the provisions of state plans in cases where states fail to do so. Congress saw fit to provide mechanisms such as conditional approval and SIP calls under CAA section 110 for the purpose of EPA evaluation and action on, and enforcement of, SIPs, and the Agency believes it is reasonable to look to section 110 as evidence of the types of mechanisms that are reasonable for EPA to provide for the same purposes under section 111(d).

These regulatory mechanisms will provide flexibility and support efficiency to the states and the EPA in the submission and processing of state plans. For the reasons discussed in the following sections, the EPA is finalizing these provisions.

1. Partial Approval and Disapproval

The EPA proposed a provision similar to that under CAA section 110(k)(3) for the EPA to partially approve and partially disapprove severable portions of a state plan submitted under CAA section 111(d). Under CAA section 110(k)(3), ''[i]f a portion of the plan revision meets all the applicable requirements of this chapter, the Administrator may approve the plan revision in part and disapprove the plan revision in part. The plan revision shall not be treated as meeting the requirements of this chapter until the Administrator approves the entire plan revision as complying with the applicable requirements of this chapter.'' Subpart Ba currently authorizes the EPA to ''approve or disapprove [the state] plan or revision or each portion thereof'' (40 CFR 60.27a(b)) but does not explicitly specify whether such actions may be partial.

One commenter stated that the partial approval and disapproval mechanisms the EPA proposed appear to be aimed at providing a way for the EPA to approve model rule provisions and disapprove RULOF provisions. The EPA disagrees with this comment. The EPA reviews each provision of a state plan, regardless of the type of provision, to determine whether it meets the applicable

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[53] These regulatory mechanisms were also previously proposed to be added to subpart B in 2015 and largely received support from states, the public, and stakeholders, but were never finalized. 80 FR 64965 (October 23, 2015).

[54] Compare CAA section 111(d)(1) (requiring states to submit state plans that include specified types of measures that, in turn, meet minimum EPA requirements) and section 111(d)(2) (indicating that the EPA must review and approve or disapprove state plans, requiring the EPA to promulgate a Federal plan if the state does not submit a satisfactory plan, authorizing the EPA to enforce state plan measures) with section 110(a)(1)–(2) (requiring states to submit SIPs that include specified types of measures that in turn meet minimum EPA requirements), section 110(k) (requiring the EPA to review and approve or disapprove SIPs), section 110(c) (requiring the EPA to promulgate a FIP if the state does not submit a plan or the EPA disapproves the state plan) and 113(a)(1) (authorizing the EPA to enforce SIP measures).

[55] See Merriam Webster's Dictionary, defining ''Similar'' as ''having characteristics in common'' or ''alike in substance and essentials.'' *https://www.merriam-webster.com/dictionary/similar.*

statutory and regulatory requirements. If it meets the applicable requirements, the EPA must approve it. It is entirely possible, and in fact common, for some state plan provisions to comport with the applicable requirements and others not to. Pursuant to this mechanism, the EPA may partially approve or partially disapprove a state plan when portions of the plan are approvable, but other discrete and severable portions are not. In such cases, the purposes of a CAA section 111(d) EG, as well as section 111(d)'s framework of cooperative federalism, would be better served by allowing the state to move forward with implementing those portions of the plan that are approvable, rather than to disapproving the full plan and potentially delaying implementation of beneficial emission reductions. This mechanism is consistent with the *ALA* decision's emphasis on ensuring timely mitigation of harms to public health and welfare, as problematic parts of a state plan submission would not stall the implementation of emission reductions at designated facilities for which a portion of a plan could be approved, thus efficiently reducing the time from EG promulgation to implementation of emission reductions at those facilities.

The EPA is finalizing this provision so that it is similar to CAA section 110(k)(3), providing clarity on the EPA's authority to partially approve plans and the circumstances under which it may be used. As explained at proposal, the portion of a state plan that the EPA may partially approve must be ''severable.'' A portion is severable when: (1) the approvable portion of the plan does not depend on or affect the portion of the plan that cannot be approved, and (2) approving a portion of the plan without approving the remainder does not alter the approved portion of a state plan in any way that renders it more stringent than the state's intent. See *Bethlehem Steel* v. *Gorsuch,* 742 F.2d 1028, 1034 (7th Cir. 1984). The EPA's decision to partially approve and partially disapprove a plan must go through notice and comment rulemaking. As a result, the public will have an opportunity to submit comment on the appropriateness and legal application of this mechanism on a particular state plan submission. A partial disapproval of a plan submission would have the same legal effect as a full disapproval for purposes of the EPA's authority under CAA section 111(d)(2)(A) to promulgate, for the partially disapproved portion of the plan, a Federal plan for the state to fill the gap. See section III.A.4 of this preamble for finalized timelines for promulgation of a Federal plan. If the EPA does promulgate a Federal plan for a partially disapproved portion, the state may, at any time, submit a revised plan to replace that portion. If the state does so, and the EPA approves the revised plan, then the EPA would withdraw the Federal plan for that state.

This partial approval/disapproval mechanism also enables states to submit, and authorizes the EPA to approve or disapprove, state plans that are partial in nature and to address only certain elements of a broader program. For example, with this mechanism, states will be able to submit partial plans intended to replace discrete portions of a Federal plan, where appropriate. Partial submittals must meet all completeness criteria.

2. Conditional Approval

The EPA proposed a mechanism analogous to the authority under CAA section 110(k)(4) to grant the EPA the ability to conditionally approve a state plan under CAA section 111(d). Under CAA section 110(k)(4), ''[t]he Administrator may approve a plan revision based on a commitment of the state to adopt specific enforceable measures by a date certain, but not later than 1 year after the date of approval of the plan revision. Any such conditional approval shall be treated as a disapproval if the state fails to comply with such commitment.'' The proposed provision would authorize the EPA to conditionally approve a plan submission that substantially meets the requirements of an EG but that requires some additional, specified revisions to be fully approvable. For the EPA to conditionally approve a submission, the state Governor or their designee must commit to adopt and submit specific enforceable provisions to remedy the stipulated plan deficiency. The provisions required to be submitted by the state pursuant to a conditional approval would be treated as an obligation to submit a plan revision and be subject to the same processes and timeframes for the EPA action as other plan revisions (*e.g.,* completeness determination, approval and/or disapproval).

Comments were generally supportive of including the mechanism in subpart Ba for use by the EPA in acting on CAA 111(d) state plans. One commenter submitted that the EPA should limit conditional approvals to plans either with only procedural deficiencies or with substantive deficiencies that (1) apply to few designated facilities (*e.g.,* no more than 5); (2) do not lead to impacts on vulnerable communities; and (3) are likely to be remedied by the state within one year. Comments were received both supporting and opposing the proposed 12-month time period for adopting and submitting the necessary revisions associated with a conditional approval. In particular, one commenter recommended allowing more than 12 months for submission of subsequent revisions that are required as part of conditional approvals that relate to RULOF provisions. After considering the comments received, the EPA is declining to explicitly limit the circumstances in which conditional approval may be used and is finalizing the 12-month period for submission of a plan revision pursuant to a conditional approval as proposed. First, the EPA views the conditional approval mechanism as a beneficial flexibility for states in instances in which partial disapproval may be appropriate because a discrete portion of a state plan does not meet the applicable requirements, but that deficiency is not so significant that it affects the substantial adequacy of the plan. CAA section 110(k)(4) supports this view, as Congress provided only 12 months for states correct the deficiency; 12 months is likely not sufficient for states to remedy significant substantive deficiencies in a plan. Thus, the EPA believes both that structure of the conditional approval mechanism already appropriately circumscribes its use and that extending the timeline for states to submit plan revisions pursuant to conditional approval would abrogate its utility as a way to address minor issues in a plan and encroach on circumstances in which partial disapproval is more appropriate. Second, under the provisions being finalized in this rulemaking, in the event that EPA did partially disapprove a state plan in lieu of conditionally approving it, the Agency would have 12 months to promulgate a Federal plan to fill the gap. See 40 CFR 60.27a(c)(2). It would be inappropriate to provide states a longer period of time in the same circumstances to remedy a deficiency.

As finalized, if the state fails to meet its commitment to submit the measures within 12 months, the conditional approval automatically converts to a disapproval. If a conditionally approved state plan converts to a disapproval due to either the failure of the state to timely submit the required measures or if the EPA finds the submitted measures to be unsatisfactory, such disapproval would be grounds for implementation of a Federal plan under CAA section 111(d)(2)(A). The EPA will publish a notice in the **Federal Register** and, if appropriate, on the public website established for the EG notifying the public that the conditional approval is converted to a disapproval. As described in section III.A.4. of this preamble, the EPA would be required to promulgate a Federal plan within 12 months of state's failure to submit the required measures or the EPA's disapproval of measures submitted to address the conditional approval.

Commenters asserted that the EPA should take action to develop a Federal plan immediately upon issuing a conditional approval, and further asserted that the EPA should not allow the conditional approval mechanism to toll the Federal plan clock and thereby delay needed public health and welfare protections. A conditional approval is not a disapproval and therefore there has been no failure on the part of the state and thus will not trigger a corresponding Federal plan for the given state nor initiate a timeline for the EPA to provide a Federal plan. Conditional approvals will be evaluated and designed on a case-by-case basis, with consideration of public health and welfare, and are expected to result in approved state plans and therefore not require the development of a Federal plan. The commenters also noted the EPA proposed to allow 12 months in which to impose a Federal plan following disapproval of a previously conditionally approved plan and stated instead the EPA should start the clock for developing a Federal plan as soon as a state plan submission is conditionally approved if the EPA has determined that there is a significant possibility that the deficiencies will not be corrected. The EPA disagrees with this comment because the Agency would not conditionally approve a plan if the deficiencies were not expected to be corrected; in this instance, a partial disapproval of the plan would be appropriate.

Another commenter requested that the EPA clarify the applicable compliance deadline for a state plan that is conditionally approved by the Agency. The commenter contended that the proposed rule did not specify the ''trigger'' date for compliance deadlines when the EPA conditionally approves a state plan, and recommended that, in this scenario, compliance deadlines should begin to run when the state satisfies the condition(s) established by the EPA. However, the EPA notes that compliance timeframes for designated facilities are specified in the applicable EGs. To the extent that the Administrator conditionally approves a plan, the compliance timeframes must still meet the requirements in the EG. A conditional approval may not be an appropriate action if the result would be a significant delay in compliance, as that is inconsistent with the intention of adding this flexibility for state plan processing.

Incorporating this mechanism under the subpart Ba will have the benefit of allowing a state with a substantially complete and approvable program to begin implementing it, while also promptly making specific changes that ensure it fully meets the requirements of CAA section 111(d) and of the applicable EGs. The EPA is therefore finalizing this provision as proposed at 40 CFR 60.27a(b)(2).

3. Parallel Processing

The EPA proposed to include a mechanism similar to that for SIPs under 40 CFR part 51 appendix V, section 2.3.1., for parallel processing a plan that does not yet meet all of the administrative completeness criteria under 40 CFR 60.27a(g)(2). This streamlined process allows the EPA to propose approval of such a plan in parallel with the state completing its process to fully adopt the plan in accordance with the required administrative completeness criteria, and then allows the EPA to finalize approval once those criteria have been fully satisfied and a final plan has been submitted.

At proposal, the EPA explained that parallel processing under subpart Ba would be subject to certain conditions. In lieu of the letter required under 40 CFR 60.27a(g)(2)(i), the state must submit the proposed plan with a letter requesting the EPA propose approval through parallel processing. Under the parallel processing procedures, a state will be temporarily exempt from the administrative completeness criteria as defined by 40 CFR 60.27a(g)(2) regarding legal adoption of the plan (40 CFR 60.27a(g)(2)(ii) and (v)) and from some of the public participation criteria (40 CFR 60.27a(g)(2)(vi), (vii), and (viii)). However, as with parallel processing for SIPs under 40 CFR part 51, appendix V, in lieu of these administrative criteria, the state must include a schedule for final adoption or issuance of the plan and a copy of the proposed/draft regulation or the document indicating the proposed changes to be made, where applicable. Note that a proposed plan submitted for parallel processing must still meet all the criteria for technical completeness as defined by 40 CFR 60.27a(g)(3) and meet all other administrative completeness criteria as defined by 40 CFR 60.27a(g)(2). If these conditions are met, the submitted plan may be considered for purposes of the EPA's initial plan evaluation and proposed rulemaking action.

The exceptions to the administrative criteria described above only apply to the EPA proposing action on the state plan. If the EPA has proposed approval through parallel processing, the state must still submit a fully adopted and final plan that meets all of the completeness criteria under 40 CFR 60.27a(g), including the requirements for legal adoption and public engagement, before the EPA can finalize its approval. If the state finalizes and submits to the EPA a plan that includes changes relative the plan that the EPA proposed to approve, the EPA will evaluate those changes for significance. If any such changes are found by the EPA to be significant (*e.g.,* changes to the stringency or applicability of a particular standard of performance), then the state submittal would be treated as an initial submission and the EPA would be required to re-propose its action on the final plan and to provide an opportunity for public comment.

Note further that once the state plan submission deadline passes, the EPA retains the authority to initiate development of a Federal plan at any time for a state that has not submitted a complete plan, even if a state has requested parallel processing and the EPA has proposed an action. The EPA intends to continue working collaboratively with states who are in the process of adopting and submitting state plans but notes that states must remain mindful of regulatory deadlines for CAA section 111(d) plan submissions even when seeking to use the parallel processing mechanism.

While comments were generally supportive of the EPA adopting parallel processing for CAA section 111(d) plans, some commenters expressed concern that the purpose and benefits of meaningful engagement would not be realized in the state plan development process if this mechanism were finalized as proposed. One commenter noted that the proposed parallel processing provision appeared to indicate that the state can submit its plan to the EPA prior to conducting meaningful engagement, and that the EPA is expecting an informational meeting rather than actual engagement from the public during the meaningful engagement process. Another commenter remarked that if a state does not include meaningful engagement before submitting its initial plan to the EPA, the proposed parallel processing mechanism creates an inherent disincentive for the state to modify a plan under this mechanism in response to any public engagement which occurs subsequent to submittal, and further stated this would increase the disparity between the feedback received from the individuals the EPA designed the meaningful engagement provisions to protect and feedback from individuals or organizations with plentiful resources for proactive engagement. The commenters also asserted that members of the public, knowing that a version of the plan is already under Federal review, would be more likely to doubt that their feedback would have an impact on the final product.

The EPA agrees with these commenters that, as proposed, exempting meaningful engagement from completeness criteria requirements under parallel processing would be a disincentive to meeting to the goals of meaningful engagement. In fact, as defined in this action, meaningful engagement is the ''*timely* engagement with pertinent stakeholders and/or their representatives in the plan development or plan revision . . .'' (emphasis added). Thus, meaningful engagement should occur well in advance of a state being ready to submit a plan to the EPA for parallel processing. The EPA is therefore excluding the meaningful engagement completeness criteria defined at 40 CFR 60.27a(g)(2)(ix) from the completeness criteria exceptions provided under the finalized parallel processing provision at § 60.27a(h)(4). That is, states must include the information required under § 60.27a(g)(2)(ix) in any proposed state plans submitted to the EPA for parallel processing. Meaningful engagement is integral in early state plan development and should be included as part of the completeness criteria for parallel processing.

The EPA is finalizing as part of the completeness criteria in 40 CFR 60.27a(g) procedural requirements for states to describe in their plan submittals how they engaged with pertinent stakeholders. The state will be required to describe, in its plan submittal, (1) a list of pertinent stakeholders identified by the state; (2) a summary of engagement conducted; (3) a summary of the stakeholder input received; and (4) a description of how stakeholder input was considered in the development of the plan or plan revisions.

4. State Plan Call

Under CAA section 110(k)(5), the EPA may call for a revision of a state implementation plan ''[w]henever the Administrator finds that the applicable implementation plan . . . is substantially inadequate to . . . comply with any requirement of [the Act].'' The EPA proposed to add a mechanism analogous to this ''SIP call'' provision to subpart Ba at 40 CFR 60.27a(i) under CAA section 111(d), which would authorize the EPA to find that a previously approved state plan does not meet the applicable requirements of the CAA or of the relevant EG and to call for a plan revision. This mechanism is a useful tool for ensuring that approved state plans continue to meet the requirements of the EGs and of the CAA over time. This may be particularly important because EGs that achieve emission reductions from specific source categories may be implemented over many years.

As proposed, the state plan call provision stated that, whenever the Administrator finds that the applicable plan is substantially inadequate to meet the requirements of the applicable EG, to provide for the implementation of such plan or to otherwise comply with any applicable requirement of subpart Ba or the CAA, the Administrator shall require the state to revise the plan as necessary to correct such inadequacies. The EPA explained that a plan call would be generally appropriate under two circumstances: when legal or technical conditions arise after the EPA approves a state plan that undermine the basis for the approval and when a state fails to adequately implement an approved state plan. In the first circumstance, a change in conditions or circumstances could render an approved plan inconsistent with the EG, subpart Ba, and/or the CAA, necessitating a plan revision to realign it with the applicable requirements. For example, a court decision subsequent to the approval of a plan may render that plan substantially inadequate to meet applicable CAA requirements resulting from the change in law.[56] Or, the EPA may determine that technical conditions, such as design assumptions, about control measures that were the basis for a state plan approval later prove to be inaccurate, meaning that the plan would be substantially inadequate to achieve the emission reductions required by the EG and therefore the plan should be revised.[57]

The second circumstance in which a state plan call may be appropriate is when a state fails to adequately implement an approved state plan. In this case, the approved state plan may facially meet all applicable requirements, but a failure in implementation (*e.g.,* due to changes in available funding, resources, or legal authority at the state level) renders the plan substantially inadequate to meet the requirements of the EG and CAA section 111(d). In this circumstance, a state, in response to a plan call, would either be required to submit a plan revision that provides for implementation of the plan's requirements given the state's actual circumstances or to provide demonstration that the plan is being adequately implemented as approved.

Consistent with the SIP call process under CAA section 110(k)(5), the EPA proposed that, after it finds that a state's approved plan is substantially inadequate to comply with applicable requirements, it would require the state to revise the plan as necessary to correct inadequacies. The EPA proposed that such finding and notice must be public. The plan call notice would identify the plan inadequacies leading to the plan call and establish a reasonable deadline (not to exceed 12 months after the date for such notice) for submission of a plan revision and/or demonstration of appropriate implementation of the approved plan.

A number of commenters asserted that the EPA is not authorized to issue a call for state plans under CAA section 111(d) because Congress did not provide this explicit authority in CAA section 111. Some commenters also expressed concern that this mechanism undermines the regulatory certainty approved plans provide to facilities. Additionally, some commenters contended that CAA sections 113 and 114 address the condition of states not properly implementing approved state plans such that a state plan call mechanism is unnecessary.

As explained at the start of this section of the preamble (section III.D.), the EPA interprets CAA section 111(d)(1)'s direction to prescribe regulations establishing a procedure similar to that provided by CAA section 110 for the submission of state plans to authorize the EPA to adopt the section 110 procedural mechanisms. Additionally, CAA section 111(d)(2) provides that EPA shall have the same authority as under CAA section 110(c) to prescribe a Federal plan where a state fails to submit a satisfactory plan, as well as the same authority as under CAA sections 113 and 114 to enforce the

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[56] An example of this circumstance in the context of CAA section 110 is the 2015 ''SSM SIP Call'', which required states to correct previously approved SIP provisions based on subsequent court decisions regarding startup, shutdown, and malfunctions (SSM) operations. 80 FR 33840, June 12, 2015.

[57] For example, the 1998 ''NO_X SIP call'' required states to submit SIP revisions addressing NO_X emissions found, after SIP approvals, to significantly impact the attainment of air quality standards in other states due to atmospheric transport. 63 FR 57356, October 27, 1998.

provisions of a state plan where the state fails to enforce them. Congress did not specify how the EPA is to exercise its authority to approve or disapprove state plans, promulgate Federal plans, and oversee and enforce state plan implementation on an ongoing basis, and the EPA finds it reasonable to look to other mechanisms under the CAA that Congress has provided for substantially the same purpose. That is, the EPA believes CAA sections 111(d)(1) and 111(d)(2), taken together, provide the legal basis for incorporating mechanisms into subpart Ba that ensure the ongoing compliance of state plans with the applicable requirements, including the state plan call mechanism of CAA section 111(k)(5).

While CAA sections 113 and 114 provide the EPA authority to enforce the provisions of state plans through, *inter alia,* issuance of administrative orders and penalties, civil actions in the case of violations, and use of monitoring, reporting, recordkeeping, and compliance certifications, the EPA believes it is also reasonable and helpful to provide a mechanism for states to bring their state plans into compliance with the applicable requirements. A state's failure to implement its approved plan may result if that plan's implementation or enforcement measures, *e.g.,* monitoring, reporting, and verification requirements, prove inadequate to enable a state to ensure that a designated facility is meeting its standards of performance. A failure to implement may also arise, as described above, where an approved state plan contains the appropriate implementation and enforcement measures but changes in, *e.g.,* available funding, resources, or legal authority at the state level render the plan, as it is being implemented, substantially inadequate to meet the requirements of subpart Ba, the EG, or CAA section 111(d). In either instance, a reasonable alternative to EPA enforcement may be for the Agency to issue a state plan call in order to give the state an opportunity to remedy the deficiency or to provide demonstration that the plan is being or will be adequately implemented as approved. As with all of the regulatory mechanisms being incorporated into subpart Ba in this rulemaking, the EPA interprets CAA sections 111(d)(1) and (2) as collectively providing the authority to provide for procedures for ensuring that state plans remain ''satisfactory'' over the long time periods over which they are implemented, given that subsequent findings or conditions may affect the basis for a previous plan approval.

The EPA acknowledges that a call for revision of a state plan may result in a change in the requirements to which regulated entities are subject under than plan. However, as explained above, state plan calls are appropriate in two general circumstances: when legal or technical conditions arise that abrogate the basis of the initial state plan approval and when a state fails to adequately implement an approved state plan. In either of these two instances, the plan as it is currently being implemented fails to meet the applicable requirements. The EPA believes it would be neither consistent with the statute nor reasonable to fail to correct a state plan under these circumstances and that the state plan call mechanism, which provides for notice to the state and the public and a process for revising the state plan that is intended to cause as little disruption to the original plan as possible, is appropriate. The state plan call provisions state that ''[a]ny finding under this paragraph shall, to the extent the Administrator deems appropriate, subject the State to the requirements of this part to which the State was subject when it developed and submitted the plan for which such finding was made, except that the Administrator may adjust any dates applicable under such requirements as appropriate.'' [58]

Several commenters noted that the proposed ''not to exceed 12 months'' timeline associated with the state call revision provision may be inadequate for states to respond to a state plan call and noted that this time is shorter than that provided for plan development. However, because a state plan call would represent that a plan is substantially inadequate to meet an EG after implementation of the plan was supposed to be underway, and compliance deadlines may have already passed, a more expeditions timeline to fix the problem than the deadline for initial plan development is imperative to the public health concerns. Additionally, the EPA anticipates that in many instances a state plan call would impact a discrete portion or element of a plan that will not require the same amount of time the EPA is allotting for initial state plan development and submission, *i.e.,* 18 months, to correct. The EPA believes 12 months is a reasonable timeframe and allows for public outreach and state processes while ensuring the deficiency is expeditiously corrected to address any outstanding public health and welfare concerns associated with a deficient plan, consistent with the *ALA* decision. However, the Agency also acknowledges that this may not be true in every instance. The EPA is therefore finalizing the state plan call mechanism with a change relative to proposal to provide that plan revisions associated to a state plan call shall be submitted to the Administrator within 12 months or within a period as determined by the Administrator, instead of ''not to exceed 12 months.'' Because the CAA contains numerous deadlines requiring states to submit various state implementation plans within 12 months of a triggering event,[59] the EPA believes it is reasonable to expect states to be able to submit state plan revisions pursuant to a state plan call within this timeframe as well. The final language provides more flexibility and allows that the EPA may supersede this 12-month timeframe in appropriate circumstances.

While this period is less than the time allotted for the submission of a full state plan (finalized in section III.A.1. of this preamble above as 18 months), it can provide a reasonable timeframe for public outreach and state processes while ensuring the deficiency is expeditiously corrected to address any outstanding public health and welfare concerns associated with a deficient plan, consistent with the *ALA* decision.

With the exception of this revision to the timeline for states to submit revised state plans, the EPA is finalizing the state plan call mechanism at 40 CFR 60.27a(i) as proposed. As explained at proposal, any failure of a state to submit necessary revisions by the date set in the call for state plan revisions constitutes a failure to submit a required plan submission. Therefore, pursuant to CAA section 111(d)(2)(A), the EPA would have the authority to promulgate a Federal plan for the state within 12 months after the necessary revisions are due. If the state fails to submit a plan revision, to make an adequate demonstration within the prescribed time pursuant to 40 CFR 60.27a(i)(1), or if the EPA disapproves a submission, then the EPA would be required to promulgate a Federal plan addressing the deficiency for sources within that state.

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[58] The regulations being finalized at § 60.27a(i)(1) further provided that if the Administrator makes the finding in § 60.27a(i) on the basis that a State is failing to implement an approved plan, or part of an approved plan, the State may submit a demonstration to the Administrator it is adequately implementing the requirements of the approved state plan in lieu of a plan revision. Such demonstration must be submitted by the deadline established under § 60.27a(i).

[59] See, *e.g.,* CAA sections 110(k)(4), 129(b)(2), and 179(d).

5. Error Correction

Under CAA section 110(k)(6), the EPA may, on its own accord, revise its prior action on a state implementation plan under certain circumstances: ''[w]henever the Administrator determines that the Administrator's action approving, disapproving, or promulgating any plan or plan revision (or part thereof) . . . was in error, the Administrator may in the same manner as the approval, disapproval, or promulgation revise such action as appropriate without requiring any further submission from the State.'' The EPA proposed to add a mechanism analogous to this ''error correction'' provision to subpart Ba at 40 CFR 60.27a(j) under CAA section 111(d) and is finalizing that mechanism as proposed.

As explained in the notice of proposed rulemaking, this error correction provision would authorize the EPA to revise its prior action when the EPA determines its own action on the state plan was in error. Specifically, this provision allows the EPA to revise its prior action in the same manner as used for the original action (*e.g.,* through rulemaking) without requiring any further submissions from the state. In this manner, the error correction mechanism does away with unnecessary burdens on states based solely on an error made by the EPA, such as submitting a plan revision and the public participation related requirements under 40 CFR 60.23a (*e.g.,* providing notice and holding a public hearing).

CAA section 110(k)(6) is phrased broadly, and its legislative history makes clear that it ''explicitly authorizes EPA on its own motion to make a determination to correct any errors it may make in taking any action, such as . . . approving or disapproving any plan.'' See House Report No. 101–490 at 220. The circumstances that may give rise to an error that the EPA may correct with this mechanism depend on the specific facts and plan at issue, and the use of the mechanism is justified on a case-by-case basis. The EPA has previously used CAA section 110(k)(6) for correction of technical or clerical errors,[60] for removal of substantive provisions from an EPA-approved state plan that did not relate to implementation, enforcement, or maintenance of the NAAQS or is otherwise permissible under the CAA for inclusion in the plan,[61] and when the EPA in error approved a SIP that did not meet applicable requirements.[62] These examples are not the only circumstances when the EPA has used CAA section 110(k)(6) in the past and do not limit the EPA for circumstances of error correction under section 111(d) in the future.

One commenter, while not objecting to the inclusion of this mechanism, suggested the EPA should make clear in the regulations that this provision cannot be used to effect a change in policy because of a change in perspective on implementation that may arise from an administration transition, citing the need for designated facilities to have regulatory certainty and to avoid unexpected changes in regulatory requirements. Other commenters also noted that the proposed regulatory text does not place any limitations on the EPA's ability to use the error correction provision and that the EPA should impose meaningful limits on its ability to use this mechanism to effectuate significant changes to a prior action or to implement new policy perspectives. The EPA acknowledges the concern expressed by the commenters. The Agency intends the same intrinsic limits on its error correction authority that exist under CAA section 110(k)(6) to apply to its use under subpart Ba: the EPA must determine that its action on a state plan submission was ''in error.'' The EPA reviews state plan submissions against the applicable requirements of the statute, general implementing regulations, and specific EG. If the submission meets those requirements, it is ''satisfactory'' and the EPA must approve it. A subsequent change in Agency policy alone does not constitute an error that the EPA committed in acting on the state plan. The EPA's history of using error correction mechanisms under CAA section 110(k)(6), including to correct clerical or typographic errors and remove provisions from SIPs that it was without authority to approve in the first instance (as described earlier), gives good indication of how the EPA intends to use this mechanism under subpart Ba. The EPA also notes that use of error correction is fact- and context-specific, and a determination that a previous action was in error is subject to scrutiny and review by the state and public. Additionally, due to the complex facts and circumstances that frequently characterize state plans and state plan implementation, the EPA believes that any attempt to further define the circumstances in which use of error correction may or may not be permissible is likely to inadvertently limit its use where otherwise appropriate. Thus, the Agency does not find it necessary to prescribe further limits on its use of error correction under these CAA section 111 implementing regulations. The EPA is therefore finalizing use of error correction for state plan actions at 40 CFR 60.27a(j) as proposed. While the EPA maintains that this error correction mechanism would be available for acting on state plans when appropriate, it also expects that it will work with states, as it has done previously in the SIP context, to correct any deficiencies in their plans.

E. Remaining Useful Life and Other Factors (RULOF) Provisions

The EPA is finalizing revisions to certain provisions of 40 CFR 60.24a to clarify the framework for applying standards of performance based on RULOF in state plans[63] under CAA section 111(d). Consistent with Congress's mandate in CAA section 111(d), the EPA's implementing regulations have guided the implementation of RULOF for decades. See 40 CFR 60.24(d), (f). The existing subpart Ba regulations[64] contain provisions at 40 CFR 60.24a(e) governing the circumstances under which states may take RULOF into consideration when applying standards of performance to particular sources in state plans. The EPA proposed revisions to these existing provisions as well as additional RULOF-related requirements to ensure consistency with the statute and to enhance clarity and equitable treatment for states. The EPA is finalizing some of these provisions as proposed, is finalizing other provisions with changes relative to proposal in response to public comments, and is choosing not to finalize yet other provisions.

Section III.E.1. of this preamble describes the statutory and regulatory background of RULOF under CAA section 111 and section III.E.2. of this preamble explains the authority and rationale for the collective regulatory revisions. Section III.E.3. of this

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[60] For example, see 74 FR 57051, November 3, 2009, for correction of clerical and typographical errors in a portion of an Arizona SIP.

[61] For example, see 86 FR 24505 (May 7, 2021) (removal of asbestos requirements from a Kentucky SIP).

[62] For example, see 86 FR 23054, April 30, 2021, for error correction with respect to Kentucky's ''good neighbor obligations'' and SIP disapproval.

[63] As explained in section III.E.1. of this preamble, any discussion and requirements that apply to states' consideration of RULOF in state plans also apply to the EPA's consideration of RULOF in the context of a Federal plan.

[64] The D.C. Circuit's vacatur of certain provisions of subpart Ba in *ALA* did not impact the existing RULOF provision at 40 CFR 60.24a(e).

preamble describes in detail the proposed RULOF provisions and the EPA's approach to each provision in this final rule.

1. Statutory and Regulatory Background

Under CAA section 111(d), the EPA is required to ''establish a procedure . . . under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for'' designated facilities and ''(B) provides for the implementation and enforcement of such standards of performance.'' As the Supreme Court explained in *West Virginia* v. *EPA* (in the context of an EG addressing existing power plants): ''Although the States set the actual rules governing existing power plans, EPA itself still retains the primary regulatory role in Section 111(d).'' [65] The Court elaborated that the ''[t]he Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, 'the best system of emission reduction . . . that has been adequately demonstrated for [existing covered] facilities.' 40 CFR part 60.22(b)(5) (2021); see also 80 FR 64664, and n. 1. The States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA. See parts 60.23, 60.24; 42 U.S.C. part 7411(d)(1).'' [66]

Accordingly, while states establish the standards of performance for individual sources, EPA must ensure that such standards reflect the degree of emission limitation achievable through the application of the BSER. This obligation derives from the definition of ''standard of performance'' under CAA section 111(a)(1), which is ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the Administrator determines has been adequately demonstrated.'' Consistent with this definition, the EPA identifies the degree of emission limitation achievable through application of the BSER for a category (or sub-category) of existing sources as part of its EG. 40 CFR 60.22a(b)(5). States must then establish standards of performance for existing sources in their state plans that reflect the EPA's degree of emission limitation.

CAA section 111(d)(1) also requires that the ''regulations which establish a procedure'' for submission of state plans must ''permit'' states, ''in applying a standard of performance to any particular source under a plan,'' to consider, ''among other factors, the remaining useful life of the existing source.'' Thus, while standards of performance must generally reflect the degree of emission limitation achievable through application of the BSER determined by the EPA pursuant to CAA section 111(a)(1), see 40 CFR 60.24a(c), CAA section 111(d)(1) also contemplates circumstances in which states would be permitted to deviate from the degree of emission limitation in the applicable EG based on consideration of RULOF for particular sources.

The 1970 version of CAA section 111(d) made no reference to the consideration of RULOF in the context of standards for existing sources.[67] In the 1975 regulations promulgating subpart B to implement the 1970 CAA section 111(d), however, the EPA included a provision that would allow states to provide ''variances'' from the EPA's emission guideline on a case-by-case basis.[68] For health-based pollutants, the regulations provided that states could apply a standard of performance less stringent than the EPA's EGs based on cost, physical impossibility, and other factors specific to a designated facility that would make the application of a less stringent standard significantly more reasonable. 40 CFR 60.24(f). For welfare-based pollutants, the regulations provided that states could apply a less stringent standard by balancing the requirements of an EG ''against other factors of public concern.'' 40 CFR 60.24(d).

In proposing this variance provision, the EPA explained that the application of less stringent emission standards on a case-by-case basis is allowed, provided that sufficient economic justification is demonstrated in each case. Such justification must be presented for each case in the plan and may include, for example, unreasonable cost of control resulting from plant age, location, or basic process design or physical impossibility of installing specified control systems.[69] In response to a comment received on its proposal arguing that the EPA did not have authority to promulgate a variance provision, the Agency explained that, although section 111(d) does not explicitly provide for variances, it does require consideration of the cost of applying standards to existing facilities. Such a consideration is inherently different than for new sources, because controls cannot be included in the design of an existing facility and because physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases. For these reasons, EPA believes the provision (§ 60.24(f)) allowing States to grant relief in cases of economic hardship (where health-related pollutants are involved) is permissible under section 111(d).[70]

The Agency further explained in the 1975 rulemaking that the ''EPA's emission guidelines will reflect its judgment of the degree of control that can be attained by various classes of existing sources without unreasonable costs.'' [71] States were required to establish emission standards for existing sources that are equivalent to the EPA's emission guidelines; states would also be free to apply more stringent standards for particular sources within a class of sources that can achieve greater control without unreasonable costs, or where they otherwise believe that additional control is necessary or desirable.[72]

As part of the 1977 CAA amendments, Congress amended CAA section 111(d)(1) in a way that codified the provision of a variance as contained in the EPA's 1975 regulations. Specifically, Congress amended CAA section 111(d)(1) to require that the EPA's regulations under this section ''shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' The EPA considered the variance provision under subpart B to meet this requirement and did not revise the provision subsequent to the 1977 CAA amendments until the Agency promulgated new implementing regulations in 2019 under subpart Ba. As part of the 2019 revisions, the EPA removed the health- and welfare-based pollutants distinction and collapsed the associated requirements of the previous variance provision into a single, then-

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[65] 142 S. Ct. 2587, 2601–02 (2022).

[66] Id. The part of the rule preamble cited by the Court states, in part: ''Under CAA section 111(a)(1) and (d), the EPA is authorized to determine the BSER and to calculate the amount of emission reduction achievable through applying the BSER. The state is authorized to identify the emission standard or standards that reflect that amount of emission reduction.'' 80 FR 64662, 64664 n. 1 (Oct. 23, 2015).

[67] See Public Law 91–604, section 111(d)(1) (Dec. 31, 1970), 84 Stat. 1684.

[68] 40 FR 53340, 53344 (Nov. 17, 1975).

[69] 39 FR 36102, 36102 (Oct. 7, 1974).

[70] 40 FR 53343.

[71] Id.

[72] See id.

new RULOF provision.[73] As did subpart B before it, this subsection provides that, in applying a standard of performance to a particular source, the state may take into consideration factors including the remaining useful life of such source, provided that the state demonstrates one or more of three circumstances: unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility of installing necessary control equipment; or other factors specific to the facility that make application of a less stringent standard or compliance time significantly more reasonable. The 2019 RULOF provision also allows, as did the 1975 version, for the variance to be provided for a particular facility or class of such facilities.

CAA section 111(d)(2) provides that ''[t]he Administrator shall have the same authority . . . to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410(c) of this title [*i.e.,* CAA section 110(c)] in the case of failure to submit an implementation plan.'' When CAA section 111(d)(2) was enacted in 1970, CAA section 110(c) stated that the Administrator shall promptly propose a Federal implementation plan for a state if ''(1) the State fails to submit an implementation plan . . . within the time prescribed, (2) the plan, or any portion thereof, submitted for such State is determined by the Administrator not to be in accordance with the requirements of this section, or (3) the State fails, within 60 days after notification by the Administrator or such longer period as he may prescribe, to revise an implementation plan as required pursuant to a provision of its plan . . . .''[74]

Thus, CAA section 111(d)(2), through its reference to CAA section 110(c), provides the EPA the authority and the obligation to review state plans for compliance with CAA requirements.[75] [76] If a state has not submitted a state plan or if the EPA determines that a state plan is not ''satisfactory,'' *i.e.,* not in accordance with the requirements of CAA section 111, the EPA must promulgate a Federal plan.

Congress further provided in CAA section 111(d)(2) that the EPA shall, in promulgating a standard of performance under a Federal plan, ''take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.'' Thus, the RULOF regulations the EPA has previously promulgated in subparts B and Ba, and the revisions to the RULOF regulations in subpart Ba being finalized in this action, apply not only to states when promulgating state plans, but also to the EPA when promulgating a Federal plan. Throughout this section III.E. of the preamble, discussion of provisions and requirements that apply to states' consideration of RULOF in state plans also apply to the EPA's consideration of RULOF in the context of a Federal plan.

2. Authority and Rationale for the Revisions

The primary authority for these revisions is in CAA section 111(d)(1). The rationale for the revisions finalized here is to more fully align the implementing regulations with the statute and to enhance clarity for states as well as the equitable treatment of states and sources.

CAA section 111(d)(1) directs the EPA to ''prescribe regulations which establish a procedure'' under which states submit state plans. These regulations must ''permit'' states, in applying a standard of performance to any particular source, to consider RULOF. That is, Congress gave the EPA the authority and the obligation to establish procedures that permit states to consider RULOF.

The EPA has been guiding consideration of RULOF for over fifty years, consistent with Congress's direction. ''Permit'' means ''to consent to formally; to allow (something) to happen, esp[ecially] by an official ruling, decision, or law.''[77] It is well understood that there may be parameters or rules as a condition of someone consenting to or allowing something to be done. For example, a building permit generally does not allow a person to build in any way they like, but contains conditions and requirements such as compliance with safety codes and limitations on height. In general, ''permit,'' whether a verb or noun, carries with it an expectation of rules and parameters designed to ensure consistency with the applicable framework, as opposed to open-ended discretion.[78] CAA section 111(d)(1) provides that ''*regulations* of the Administrator . . . *shall permit* the State'' to consider RULOF (emphasis added). The natural reading of this provision is that Congress intended the EPA to set out parameters and conditions that govern states' consideration of RULOF.[79]

The EPA's role in implementing RULOF finds further support in the Supreme Court's understanding of this provision as laid out in *American Electric Power* v. *Connecticut.*[80] In describing the statutory framework of CAA section 111, the Court explained that the EPA sets standards of performance based on CAA section 111(a)(1). It further recognized that, pursuant to the EPA's subpart B general implementing regulations for state plans, 40 CFR 60.24(f), ''EPA may permit state plans to deviate from generally applicable emissions standards upon demonstration that costs are '[u]n-reasonable.' ''[81]

At the same time that Congress clearly directed the EPA to prescribe rules governing states' consideration of RULOF, it also provided that those rules establish a *procedure* under which

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[73] 84 FR 32520, 32577 (July 8, 2019).

[74] Public Law 91–604, section 110(c) (Dec. 31, 1970), 84 Stat. 1681–82.

[75] See also 40 CFR 60.27(c) (''The Administrator will, after consideration of any State hearing record, promptly prepare and publish proposed regulations setting forth a plan, or portion thereof, for a State if: (1) The State fails to submit a plan within the time prescribed; . . . (3) The Administrator disapproves the State plan or plan revision or any portion thereof, as unsatisfactory because the requirements of this subpart have not been met.''); 60.27(d) (providing for promulgation of a proposed Federal plan).

[76] Congress subsequently updated CAA section 110(c) in 1977 and again in 1990. The current version of CAA section 110 splits the EPA's Federal implementation plan authority and the criteria for disapproval of State implantation plans across subsections 110(c) and 110(k)(3). CAA section 110(c)(1) provides that ''[t]he Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—'' (A) finds that a State has failed to make a complete plan submission, or ''(B) disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal plan.'' CAA section 110(k)(3), which addresses ''[f]ull and partial approval and disapproval,'' states that the Administrator shall approve all or certain portions of the plan that ''meet[] the applicable requirements of this chapter.'' Thus, a plan, or any portion thereof, that fails to meet the applicable CAA requirements must be disapproved.

[77] Black's Law Dictionary (11th ed. 2019); *see also* The American College Dictionary (1970) (''to let (something) be done or occur''); Oxford English Dictionary Online (''to allow or give consent to (a person or thing) to do or undergo something''), *https://www.oed.com/search/dictionary/?scope=Entries&q=permit,* page accessed Sept. 1, 2023.

[78] See, *e.g., U.S.* v. *Chau,* 293 F.3d 96, 101 (3d Cir., 2002) (a provision requiring an entity to provide notice to the EPA prior to acting is not a ''permit'' because ''[a] requirement that someone provide written notice of an intention to perform an act is not the same at the EPA's granting of a license, or other permission, to the person to perform the act in question . . . .'').

[79] This contrasts with other provisions of the Clean Air Act where Congress granted states unbounded discretion. *See, e.g.,* CAA section 116 (''nothing in this chapter shall preclude or deny the right of any State or political subdivision thereof to adopt or enforce'' more stringent requirements).

[80] 564 U.S. 410 (2011).

[81] Id. at 427.

states submit state plans, including any standards of performance pursuant to consideration of RULOF. CAA section 111(d)(1) states, ''The Administrator shall prescribe regulations which shall establish a procedure . . . . Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' Consistent with this statutory direction, the EPA's RULOF provisions, both the existing provisions and those being finalized in this action, are fundamentally procedural in nature. They prescribe the series of steps and considerations states must undertake to apply a less stringent standard of performance that is consistent with CAA section 111(d).

As discussed in section III.E.1. of this preamble, Congress also granted the EPA a role in ensuring that states applying standards of performance based on RULOF do so in an appropriate manner. CAA section 111(d)(2) requires the EPA to evaluate standards of performance in state plans and approve them only if they are ''satisfactory,'' *i.e.,* if they meet the applicable requirements.[82] Thus, while states have responsibility for establishing, implementing, and enforcing standards of performance for designated facilities, the EPA has an obligation to ensure that those standards of performance—including any standards of performance based on consideration of RULOF—are consistent with the statute. The regulations the EPA is promulgating in this final rule provide greater clarity and thus enable states to apply less stringent standards of performance that are consistent with CAA section 111(d). Having clear, detailed regulations also aids the EPA in evaluating less stringent standards of performance included in state plans, which maximizes the Agency's ability to provide for fair and equitable treatment across the states and sources that use the RULOF provision.

In addition, the parameters for considering RULOF set out in this final rule are consistent with the role of RULOF as an important tool for states in the unusual circumstance in which the EPA's BSER determination is unreasonable for a particular source. As explained in detail in section III.E.3.b. of this preamble, the EPA's longstanding interpretation is that RULOF provision in CAA section 111(d)(1) allows the Agency to permit states to provide variances for existing facilities in certain circumstances. These circumstances are limited to when a state can demonstrate that it is unreasonable for a particular facility to achieve the degree of emission limitation determined by the EPA in the applicable EG.

Under CAA section 111, EPA must provide BSER and degree of emission limitation determinations that are, to the extent reasonably practicable, applicable to all designated facilities in the source category. In many cases, this requires the EPA to create subcategories of designated facilities, each of which has a BSER and degree of emission limitation[83] tailored to its circumstances.[84] Thus, the EPA endeavors, to the extent practicable, to promulgate BSER and degree of emission limitation determinations that are achievable for all designated facilities covered by an EG. However, as Congress recognized, this may not be possible in every instance because, *e.g.,* it is not be feasible for the Agency to know and consider the idiosyncrasies of every designated facility in a source category or because the circumstances of individual facilities change after the EPA determined the BSER. The EPA believes Congress intended RULOF to allow the EPA to permit the use of variances for states to adjust a standard of performance in unusual circumstances in which the EPA's determination regarding the degree of emission limitation achievable through the BSER is not reasonable for a particular designated facility.

This view of the RULOF provision as a limited variance from the EPA's determinations in an EG has a long history. The EPA's description of how it develops EGs in the preamble to the 1975 subpart B implementing regulations stated that ''emission guidelines will reflect subcategorization within source categories where appropriate, taking into account differences in sizes and types of facilities and similar con- . . . siderations [*sic*], including differences in control costs that may be involved for sources located in different parts of the country.''[85] As a result, emission guidelines ''will in effect be tailored to what is reasonably achievable by particular classes of existing sources, and States will be free to vary from the levels of control represented by the emission guidelines in the ways mentioned above.''[86] The ''ways mentioned above'' included establishing more stringent standards under CAA section 116 where states believe additional control is necessary or desirable, as well as setting more lenient standards, subject to EPA review, in cases of economic hardship.[87] The EPA subsequently explained that such cases could arise because controls were not included in the design of existing sources or because physical limitations may make installation of particular control systems impossible or unreasonably expensive in some cases.[88]

Thus, the EPA's long-standing interpretation is that the standards of performance established by states must generally reflect the degree of emission limitation determined by the Agency, except where, based on RULOF, states provide ''sufficient justification'' that the EPA's determination is ''unreasonable'' for a particular source.[89] Although the EPA endeavors to address the circumstances of all designated facilities in its EG, there may remain instances in which the circumstances of a particular facility justify application of a less stringent standard of performance.

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[82] CAA section 111(d)(2)(A) authorizes the EPA to promulgate a Federal plan for any state that ''fails to submit a satisfactory plan'' under section 111(d)(1). Accordingly, the EPA interprets ''satisfactory'' as the standard by which the EPA reviews state plan submissions. The EPA discusses the ''satisfactory'' standard of review in greater detail in section III.E.3.b of this preamble.

[83] The EPA, in different contexts, uses the phrase ''degree of emission limitation'' to refer to both the degree of emission limitation achievable through application of the BSER at the level of an individual source, *e.g.,* the best system can achieve an 85% reduction in end-of-stack emissions when applied to a designated facility, and to the overall level of stringency that results from applying the BSER to the source category as a whole. In this section of the preamble, this phrase refers to the emission reductions that are achievable at an individual source.

[84] See 40 CFR 60.22a(b)(5) (EPA may specify different degrees of emission limitation and compliance times for different subcategories of designated facilities).

[85] 40 FR 53343.

[86] Id.

[87] See id.

[88] Id. at 53344. Similarly, in the 1974 notice of proposed rulemaking for the subpart B regulations, the EPA explained that ''it is the Administrator's judgment that section 111(d) permits him to approve State emission standards only if they reflect application of the best systems of emission reduction (considering the cost of such reduction) that are available.'' The EPA further stated: ''It is recognized, however, that application of such standards may be unreasonable in some situations. For example, to require that existing controls be upgraded by a small margin at a relatively high cost may be unreasonable in some cases. The proposed regulations, therefore, provide that States may establish less stringent emission standards on a case-by-case basis provided that sufficient justification is demonstrated in each case.'' 39 FR 36102, 36102 (Oct. 7, 1974).

[89] 39 FR 36102; see also 40 CFR 60.24(c), (f) (EPA's longstanding regulations in subpart B require standards of performance in state plans to be no less stringent than the corresponding EG except where a state has satisfied the regulatory requirements for invoking RULOF).

Finally, and relatedly, to be consistent with the statutory purpose of reducing dangerous air pollution under CAA section 111; the statutory framework under which to achieve that purpose the EPA is directed to set the degree of emission limitation achievable through application of the best system of emission reduction; and the history of the statutory RULOF provision as a limited variance from that degree of emission limitation to address unusual circumstances at particular facilities, the EPA's regulations must ensure that application of less stringent standards of performance pursuant to consideration of RULOF does not undermine the degree of emission limitation achievable through application of the BSER.

Thus, for the reasons explained above, the EPA has the authority to promulgate the regulatory updates included in this final rule, which flow from the statute's direction for the Agency to ''establish procedures'' that, among other things, ''permit'' states to consider RULOF. The EPA believes these updates are warranted to provide additional clarity to the states (when developing state plans) and the EPA (when issuing Federal plans and reviewing state plans) regarding the appropriate procedures for considering RULOF and to ensure the predictable and equitable treatment of states and sources in implementing EGs under CAA section 111(d). Furthermore, the updates to the framework are needed to ensure that consideration of RULOF adheres to statutory purpose, structure, and historical context discussed above.

Critically, the regulatory revisions also provide a framework for how states and the EPA calculate and apply less-stringent standards of performance. Neither the RULOF provision in subpart B nor the 2019 update to that provision in subpart Ba clearly delineate the process for states or the EPA after they have determined that a source cannot reasonably achieve the degree of emission limitation in the applicable emission guideline. As such, the existing regulations are not adequate to ensure that standards of performance pursuant to RULOF are no less stringent than required to address the basis for providing a variance from the EPA's degree of emission limitation in the first instance.

Consistent with the long-held interpretation of the RULOF provision as a limited variance, the EPA is aware of only a small handful of instances in which a state has used this provision to apply a less-stringent standard of performance to a designated facility in a state plan. In three of these instances, the Agency approved less stringent standards of performance for welfare-related designated pollutants for which, under subpart B (40 CFR 60.24(d)), there was a lower bar for doing so.[90] In the fourth instance, the state invoked RULOF to apply a less-stringent standard for a health-related designated pollutant and the EPA disapproved the less-stringent standard for failing to satisfy the requirements of 40 CFR 60.24(f).[91] At the time of this rulemaking, however, there are two new EGs for which rulemaking is ongoing; each of these EGs would address large, complex, and highly diverse source categories.[92] Commenters on these proposed EGs have suggested that there may be more of a role for RULOF than in past EGs.[93] The revisions to the RULOF provisions are thus timely to give states greater clarity on and predictability for applying less stringent standards of performance consistent with CAA section 111.

Note that the RULOF provisions are distinct from the flexible compliance mechanisms such as trading and averaging, discussed in section III.G.1. of this preamble. The RULOF provisions apply where a state intends to *depart* from the degree of emission limitation in the EG and propose a less stringent standard for a designated facility (or class of facilities). That is, the RULOF provisions are relevant to a state's process of applying a standard of performance to a designated facility in the first instance. In contrast, trading and averaging are mechanisms that, when permitted in an EG, states may use to demonstrate compliance with the standards of performance that are contained within their state plans.

3. Proposed and Finalized RULOF Provisions

The EPA proposed revisions to the existing RULOF provision at 40 CFR 60.24a(e), which details the circumstances under which states or the EPA may apply a less stringent standard of performance. The EPA also proposed to add new provisions: a procedure for determining less stringent standards when a state has properly invoked RULOF (proposed and finalized at 40 CFR 60.24a(f)); a clarification that state plans may not apply less stringent standards if a designated facility can reasonably achieve the presumptive standard of performance using a technology other than the BSER (proposed at 40 CFR 60.24a(g)); a clarification that any less stringent standards must meet all other applicable requirements (proposed at 40 CFR 60.24a(l), finalized at 60.24a(h)); requirements related to when operating conditions that are relied on for a less stringent standard must be included as enforceable requirements in state plans (proposed at 40 CFR 60.24a(h), finalized at 40 CFR 60.24a(g)); requirements related to the consideration of remaining useful life (proposed 40 CFR 60.24a(i)); a clarification regarding the burden of proof and information on which RULOF demonstrations are based (proposed 40 CFR 60.24a(j));

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[90] 49 FR 35771 (Sept. 12, 1984), 47 FR 50868 (Nov. 10, 1982), 47 FR 28099 (June 29, 1982). See, *e.g.,* Emission Guideline Document for Kraft Pulping: Control of TRS Emissions from Existing Mills, EPA–450/2–78–003b (March 1979) at 1–3 (''For Welfare-related pollutants, states may balance the emission guidelines, times for compliance, and other information in a guideline document against other factors of public concern in establishing emission standards, compliance schedules, and variances provided that appropriate consideration is given to the information presented in the guideline document and at public hearing(s) required by Subpart B and that all other requirements of Subpart B are met. . . . Thus, states will have substantial flexibility to consider factors other than technology and costs in establishing plans for the control of welfare-related pollutants if they wish.'').

[91] See 40 CFR 62.8860(a) (''The requirements of § 60.24(f) of this chapter are not met because the State failed to justify the application of emission standards less stringent than the Federal emission standards.''); see also 55 FR 19883, 19884 (May 14, 1990) (explaining the proposed less-stringent limits were not approvable because the state had not demonstrated sufficient justification). The RULOF provision that governed that action in subpart B was substantively identical to the version promulgated in 2019 in subpart Ba.

[92] Proposed Rule: ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' 86 FR 63110 (Nov. 15, 2021); Supplemental Proposal: Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,'' 87 FR 74702 (Dec. 6, 2022); Proposed Rule: New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule,'' 88 FR 33240 (May 23, 2023).

[93] See, *e.g.,* Comment Letter of Pioneer Natural Resources USA, Inc. on Supplemental Notice of Proposed Rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector (''Oil and Gas Proposed Rule''), EPA–HQ–OAR–2021–0317–2298 at 20–21; Comment Letter of American Petroleum Institute on Oil and Gas Proposed Rule, EPA–HQ–OAR–2021–0317–2428 at 93–95, 102–104; Comment Letter of Power Generators Air Coalition on New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (''EGU Proposed Rule''), EPA–HQ–OAR–2023–0072–0710 at 75–78; Comment Letter of Wisconsin Department of Natural Resources and Public Service Commission of Wisconsin on EGU Proposed Rule, EPA–HQ–OAR–2023–0072–0538 at 1–2, 10–11.

requirements to consider potential impacts and benefits of control to communities most affected by and vulnerable to emissions from a designated facility for which a state is proposed a less stringent standard (proposed 40 CFR 60.24a(k)); and a clarification that states may account for other factors in applying a more stringent standard of performance (proposed 40 CFR 60.24a(m)). In addition, the EPA proposed changes to the existing 40 CFR 60.24a(f) (proposed at 40 CFR 60.24a(n), finalized at § 60.24(i)) reflecting the Agency's revised interpretation that CAA sections 111(d) and 116 authorize states to include standards of performance more stringent than the EPA's presumptive standards in their state plans as enforceable requirements.

The EPA received a wide range of comments on its proposed RULOF provisions. Some commenters expressed support for the proposed revisions, noting that the EPA has the authority to specify how RULOF is implemented and the obligation to ensure that its use does not undermine the emission reductions that are achievable through application of the BSER. Supportive commenters also noted that providing a regulatory structure is important to ensure that RULOF is applied in a reliable, consistent, and appropriate manner. Commenters opposed to the proposed RULOF revisions stated that there is no basis in the statute for the EPA to restrict states' authority to consider RULOF and apply less-stringent standards of performance. Some commenters also argued that the EPA's proposed regulations were too prescriptive and burdensome. Other commenters generally supported the EPA's proposed revisions but had questions or concerns regarding specific provisions, including the requirements around source-specific standards of performance and consideration of impacted communities. One commenter requested that the EPA clarify that the revised RULOF provisions would apply to design, equipment, work practice, or operational standards issued under CAA sections 111(d) and 111(h)(1).

After consideration of these comments, the EPA is finalizing a subset of the requirements that it proposed. As a general matter, the EPA is finalizing as requirements the provisions that must apply under any EG to provide necessary clarity to both the states and the EPA in applying or approving less stringent standards of performance. This clarity and predictability with regard to what constitutes a satisfactory, and therefore approvable, less stringent standard is crucial to ensuring the equitable treatment of states and sources that are considering RULOF in state plans. The requirements the EPA is finalizing are additionally necessary to ensure that use of RULOF is consistent with the statutory purpose of reducing emissions of dangerous air pollutants, the framework under which the EPA is directed to achieve that purpose through determining the degree of emission limitation, and history of RULOF as a limited variance to address unusual circumstances when it is not possible for a particular facility to achieve the EPA's degree of emission limitation. The proposed RULOF provisions that are not being included as regulatory requirements remain important considerations when applying RULOF; however, the EPA is not finalizing them in these general implementing regulations.

The EPA recognizes that in finalizing these updates it is imposing certain requirements on states' use of RULOF. Consistent with the framework of cooperative federalism under which CAA section 111(d) operates, states apply standards of performance pursuant to consideration of RULOF, as well as provide the compliance measures for implementing such standards, subject to the applicable statutory requirements. The Agency again notes that it has placed requirements on states' ability to apply less stringent standards of performance since it first created a variance provision in subpart B in 1975. See 40 CFR 60.24(c) through (e). When Congress later adopted the RULOF provision into the statute, it directed the EPA in CAA section 111(d)(1) to establish a procedure *permitting* states to consider RULOF. Moreover, as discussed further in section III.E.3.b, these updates are consistent with the historical interpretation of RULOF as a variance from the EPA's degree of emission limitation. The EPA also notes that the requirements being finalized in this action establish a process for states in applying less stringent standards of performance. These final regulations ensure, consistent with the statutory purpose, that any less stringent standards are no less stringent than necessary to address the reason that the variance is needed in the first place.

Finally, the EPA confirms that the RULOF provisions, including those being finalized in this action, apply to standards of performance promulgated pursuant to CAA sections 111(d) and 111(h)(1). The existing definition of ''standard of performance'' in 40 CFR 60.21a(f) includes ''a legally enforceable regulation . . . prescribing a design, equipment, work practice, or operational standard, or combination thereof.'' Therefore, the RULOF provisions in 40 CFR 60.24a, which may be invoked to apply a ''standard of performance'' to a particular designated facility, also apply to standards of performance applied under CAA section 111(h)(1).[94]

a. Threshold Requirements for Considering Remaining Useful Life and Other Factors

The existing RULOF provision at 40 CFR 60.24a(e) addresses the circumstances in which states may invoke RULOF to deviate from the BSER and degree of emission limitation determinations the EPA has made pursuant to CAA section 111(a)(1). It allows states to consider RULOF to apply a less stringent standard of performance for a designated facility or class of facilities if they demonstrate one of the three following circumstances: (1) unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility of installing necessary control equipment; or (3) other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

As discussed in the notice of proposed rulemaking, the proposed amendments largely retained this provision, including the three circumstances under which a less stringent standard of performance may be applied, and provided further clarification of what a state must demonstrate in order to invoke RULOF in a state plan. Specifically, the proposed amendments required the state to demonstrate that a particular facility cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA, based on one or more of the three circumstances. The EPA's proposal retained the first circumstance in whole and revised the second circumstance to add the ''technical infeasibility'' of installing a control as another situation in which application of RULOF may be appropriate. The proposal further clarified the third circumstance for invoking RULOF, the existing version of which provides that states may invoke RULOF when other factors specific to the facility make a less stringent standard of performance ''significantly more reasonable.'' The EPA proposed to revise this circumstance, under which the first two circumstances also fall, to specify that states may consider RULOF

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[94] See also 40 CFR 60.24a(b).

to apply a less stringent standard if circumstances specific to a facility are fundamentally different from the information the EPA considered in determining the BSER. This proposed clarification was intended to provide clear parameters for developing and assessing state plans, as the existing third circumstance is vague and potentially open-ended.

The EPA explained at proposal that the revisions clarified the RULOF provision by tethering a state's RULOF demonstration to the statutory factors the EPA considered in the BSER determination. As discussed in section III.E.1. of this preamble, CAA section 111(a)(1) gives the EPA the responsibility of determining the BSER and degree of emission limitation that is required of designated facilities in the source category; the EPA endeavors, to the extent reasonably practicable based on the information before it, to promulgate determinations that are achievable for every designated facility covered by an EG. Per the statutory requirements, the EPA determines the BSER by first identifying control methods that it considers to be adequately demonstrated and then determining which is the best system of emission reduction by evaluating the statutory factors: (1) the cost of achieving such reduction, (2) nonair quality health and environmental impacts, (3) energy requirements, and (4) the amount of emission reductions.[95] The EPA's BSER determination thus represents a system that is ''adequately demonstrated'' and reasonable for sources broadly within the source category; CAA section 111(a)(1) requires that standards of performance must reflect the degree of emission limitation that is achievable through application of the BSER.

In considering the BSER, the D.C. Circuit has stated that to be ''adequately demonstrated,'' the system must be ''reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973). Thus, in making the BSER determination, the EPA must evaluate whether a system of emission reduction is ''adequately demonstrated'' for the source category or sub-category based on the physical possibility and technical feasibility of control. Similarly, the court has interpreted CAA section 111(a)(1) as using reasonableness in light of the statutory factors as the standard in evaluating cost, so that a control technology may be considered the ''best system of emission reduction . . . adequately demonstrated'' if its costs are reasonable (*i.e.,* not exorbitant, excessive, or greater than the industry can bear), but cannot be considered the BSER if its costs are unreasonable.[96] In light of the statutory factors the EPA is required to consider, it follows that most designated facilities within the source category or subcategory should be able to implement the BSER at a reasonable cost to achieve the degree of emission limitation determined by the EPA. Consideration of RULOF is appropriate only for particular sources for which implementing the BSER to achieve that degree of emission limitation would impose unreasonable costs or would otherwise not be feasible due to facility-specific circumstances that are not applicable to the broader source category (or subcategories) and that the EPA did not consider in determining the BSER.

For example, if the EPA applied a specific cost threshold in determining the BSER, application of RULOF based on cost would only be appropriate where the cost of achieving the associated degree of emission limitation at a particular designated facility is unreasonably high relative to the costs the EPA considered for the BSER. Or, by way of further example, if the EPA were to determine that a specific back-end control technology is adequately demonstrated and the BSER for a source category, a state may need to evaluate whether it would be physically possible to install that control technology at a designated facility given the particular size and physical constraints of that facility. Application of RULOF to deviate from the EPA's determinations pursuant to CAA section 111(a)(1) may be appropriate, *e.g.,* where the state could show that the cost of achieving the degree of emission limitation would be significantly higher at a specific designated facility than the cost-per-ton EPA considered in setting the BSER, or that a specific designated facility does not have adequate space to reasonably accommodate the installation of the BSER and the facility cannot reasonably achieve the degree of emission limitation using a different control technology. The EPA proposed to require states to hew to the same types of factors and analyses the EPA's considered in its BSER determination when demonstrating that the EPA's determinations are not reasonable for a particular designated facility; the Agency explained that this would be consistent with the statutory framework under which RULOF is a limited exception to the level of stringency otherwise required by the BSER.[97]

Related to the proposed revisions at 40 CFR 60.24a(e), the EPA also proposed to add new § 60.24a(g) to the regulations, which would explicitly provide that a state plan may not apply a less stringent standard of performance in cases where a designated facility cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA, but *can* reasonably implement a different technology or other system to achieve that same degree of emission limitation. This is consistent with the statutory framework, which does not require sources to implement the EPA's BSER but rather permits states to allow their sources to comply with their standards of performance using systems of their choosing.

The EPA received a range of comments on the proposed revisions to the threshold circumstances for invoking RULOF to apply a less-stringent standard of performance. Some commenters agreed with the EPA that the existing criteria are not specific or clear enough to ensure that RULOF is invoked only when a designated facility cannot achieve the degree of emission limitation that the EPA has determined pursuant to section 111(a)(1). Several commenters supported the EPA's proposal that application of RULOF is only appropriate where a facility cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA based on fundamental differences between that facility and the factors the EPA considered in the BSER determination. Some commenters also urged the EPA to explicitly apply the ''fundamentally different'' standard to all three circumstances under 40 CFR 60.24a(e).

However, other commenters argued that the EPA cannot preclude states from considering factors specific to particular facilities on the basis that the EPA did not consider those factors in

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[95] Although CAA section 111(a)(1) may be read to state that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination, the D.C. Circuit's case law may be read to treat them as part of the ''best'' determination. *See Sierra Club* v. *Costle,* 657 F.2d 298, 330 (D.C. Cir. 1981). Under either approach, the EPA's analysis and ultimate determination as to the BSER would be the same. In determining the ''best'' system of emission reduction, the EPA also considers the advancement of technology, consistent with D.C. Circuit caselaw. See id. at 347.

[96] See *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999), *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981), *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[97] 87 FR 79199.

determining the BSER, and that the ''fundamentally different'' standard unlawfully narrows states' consideration of site-specific factors under the third RULOF criterion. Some commenters further contended that states should have wide latitude and flexibility to consider RULOF and that the EPA lacks authority to restrict states' abilities to apply RULOF in circumstances they deem appropriate. The EPA also received a request from one commenter asking the Agency to clarify how the proposed provisions at 40 CFR 60.24a(e) and (g) interact with each other.

The EPA is finalizing the provisions for invoking RULOF at 40 CFR 60.24a(e) with clarifying revisions relative to proposal. Based on these changes, the proposed addition of 40 CFR 60.24a(g) is redundant; the EPA is therefore not finalizing this provision.

These revisions to 40 CFR 60.24a(e) are necessary to ensure that state plans comply with CAA section 111(d). As explained above, the EPA's determination of the degree of emission limitation achievable through application of the BSER is the level of stringency required by CAA section 111(d), unless it can be demonstrated that something about the EPA's determination does not hold true for a particular designated facility. The enumerated circumstances for invoking RULOF in 40 CFR 60.24a(e) mirror the information the EPA considers in making its BSER and degree of emission limitation determination pursuant to CAA section 111(a)(1): information related to determining that a system is adequately demonstrated (including physical possibility and technical feasibility), the cost of achieving emission reductions, and other factors, which include nonair quality health and environmental impacts and energy requirements. Thus, the long-standing RULOF provision [98] is formulated for states to examine, at a minimum, the same factors the EPA considered in determining the BSER in order to determine the reasonableness of the EPA's BSER and degree of emission limitation as it applies to a particular designated facility. In this action, the EPA is clarifying the circumstances in 40 CFR 60.24a(e) for invoking RULOF in order to provide more objective and consistent criteria that will aid both states and the EPA in developing and reviewing standards of performance consistent with CAA section 111(d), as well as ensure the equitable treatment of states and sources that avail themselves of the RULOF provision.

The EPA disagrees with commenters who argued that the proposed revisions to the third circumstance unlawfully constrain states' authority to invoke RULOF. On the contrary, the EPA believes these revisions provide necessary clarity to ensure that states invoke RULOF in appropriate circumstances. First, as discussed more fully in section III.E.2. of this preamble, Congress directed the EPA to promulgate regulations for the submission of state plans that ''permit'' states to consider RULOF. Rather than granting states unfettered discretion to consider RULOF in applying standards of performance, the statute directs the EPA to establish regulations describing the ''permissible'' use of such consideration. Thus, the EPA has the authority and obligation to guide states' consideration of RULOF.

Second, the revisions to 40 CFR 60.24a(e) provide a clear and easily replicable standard for when it is appropriate to apply a less stringent standard of performance: when there are fundamental differences between the information the EPA considered in determining the degree of emission limitation and the information specific to a facility that make the EPA's degree of emission limitation unreasonable for the facility. In addition to clarifying the circumstances under which consideration of RULOF is appropriate, this standard also provides greater specificity that will aid both states and the EPA in implementing the provision. This standard is further consistent with statutory purpose, structure, and history of CAA section 111(d), under which the generally applicable requirement is the degree of emission limitation determined by the EPA and RULOF serves as a variance to that requirement.[99] Moreover, the revisions to 40 CFR 60.24a(e) will provide a framework for the EPA to use when considering any requests for less stringent standards of performance when the Agency is promulgating a Federal plan, which is again critical to ensuring both the equitable treatment of states and sources and the integrity of an EG's emission reduction purpose.

This revision will additionally provide the EPA with clear criteria to use when evaluating any invocation of RULOF in state plans to determine whether providing a less-stringent standard of performance is consistent with the statutory framework and therefore approvable as ''satisfactory.'' As noted above, it provides an objective, replicable benchmark against which to assess states' plans, which can be further elaborated on in individual EGs.

The ''fundamentally different'' standard ensures that RULOF is invoked for circumstances where application of the statutory factors would lead to a result that is outside the realm of what the EPA considered reasonable in determining the BSER. The EPA makes BSER determinations on a source category, or sub-category, basis. Necessarily, therefore, the Agency considers information relevant to potential BSERs for representative, average units or as average values for the set of designated facilities. Implicit in an EPA determination that a system is the BSER based on average, representative information is a determination that values around those average representative values are also reasonable, including some portion of unit-specific values that will deviate from but are not significantly different than the average representative values. Therefore, in order to justify deviating from the EPA-determined degree of emission limitation, the circumstances of a particular source must be not just different but fundamentally different from those the Agency considered in determining the BSER.

Furthermore, as explained at proposal, the ''fundamentally different'' standard is also consistent with other variance provisions that courts have upheld for environmental statutes. For example, in *Weyerhaeuser Co.* v. *Costle,*[100] the court considered a regulatory provision promulgated under the Clean Water Act (CWA) that permitted owners to seek a variance from the EPA's national effluent limitation guidelines under CWA sections 301(b)(1)(A) and 304(b)(1). The EPA's regulation permitted a variance where an individual operator demonstrates a ''fundamental difference'' between a CWA section 304(b)(1)(B) factor at its facility and the EPA's regulatory findings about the factor ''on a national basis.'' [101] The court upheld this standard as ensuring a meaningful opportunity for an operator to seek dispensation from a limitation that would demand more of the individual facility than of the industry generally, but also noted that such a provision is not a license for avoidance of the Act's strict pollution control requirements.[102]

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[98] The circumstances for invoking RULOF in the existing subpart Ba provision at 40 CFR 60.24a(e) are identical to those in the original variance provision of subpart B at 40 CFR 60.24(f).

[99] See the discussion in section III.E.3.b. of this preamble.

[100] 590 F.2d 1011 (D.C. Cir. 1978).

[101] Id. at 1039.

[102] Id. at 1035.

The EPA is revising the regulatory text of 40 CFR 60.24a(e) relative to proposal to explicitly provide that the ''fundamentally different'' standard applies to all three categories of circumstances for invoking RULOF. This change is consistent with the stated intent at proposal; for example, the EPA proposed ''to require that, in order to demonstrate that a designated facility cannot reasonably meet the presumptive level of stringency based on one of these three criteria, the state must show that implementing the BSER is not reasonable for the designated facility due to fundamental differences between the factors the EPA considered in determining the BSER, such as cost and technical feasibility of control and circumstances at the designated facility.'' [103] As explained above, in order to be consistent with the statutory framework, the fundamentally different standard necessarily applies to any consideration that may be cause to invoke RULOF to provide a less-stringent standard of performance.

There may be instances in which the EPA has not considered, in making its BSER determination, a circumstance that makes the BSER unreasonable for a particular facility because that circumstance is not applicable to the average or typical designated facility in the source category. Where the EPA did not consider a circumstance that is relevant to a particular designated facility and that circumstance causes the BSER to be unreasonable for that facility due to one or more of the reasons enumerated in 40 CFR 60.24a(e), a state may find there is a fundamental difference from the information the EPA considered in determining the degree of emission limitation achievable through application of the BSER. That is, if the EPA did not consider any information pertaining to a certain circumstance in making its determination, facility-specific information relevant to that circumstance that demonstrates that achieving the degree of emission limitation is unreasonable pursuant to 40 CFR 60.24a(e) may be ''fundamentally different'' from the information the EPA considered. The EPA notes that, in many cases, facility-specific circumstances can be considered in terms of differences in cost. For example, an issue of the technical feasibility of implementing a control to achieve a certain degree of emission limitation may, at its root, be an issue of being able to achieve that degree of emission limitation *at a reasonable cost.* Because cost is generally a more quantifiable and replicable metric, where possible the EPA expects states to include the impacts of any facility-specific circumstances in the cost calculation, rather than evaluating those circumstances under a different factor or consideration.

The EPA is also finalizing its proposed clarifying revisions to 40 CFR 60.24a(e) with further updates. The existing provision in subpart Ba was not clear, unless it was read directly in conjunction with 40 CFR 60.24a(c), that its specific purpose is application of less stringent standards of performance pursuant to consideration of RULOF; it did not mention less stringent standards until 40 CFR 60.24a(e)(3).[104] The EPA therefore proposed and is finalizing revisions so that the provision's purpose is now clearly stated at the outset. The EPA is also making two further revisions relative to the proposed 40 CFR 60.24a(e). First, it is adding back in language allowing the RULOF provision to be used to provide a compliance schedule longer than otherwise required by an applicable emission guideline. In proposing to revise 40 CFR 60.24a(e), the EPA inadvertently deleted the phrase ''that make application of a less stringent . . . final compliance time significantly more reasonable'' in the document containing redline/strikeout of the subpart Ba regulations.[105] It was not the EPA's intent to preclude the use of RULOF to provide a longer compliance schedule; this has been part of the provision since the original variance in 1975.[106] However, as the language pertinent to providing a longer compliance time no longer fits in its original sub-paragraph, the EPA is adding this allowance back elsewhere in 40 CFR 60.24a(e).

Second, the EPA is revising this provision relative to proposal to change the circumstances under which invoking RULOF is appropriate from the state demonstrating that ''the facility cannot reasonably apply the best system of emission reduction to achieve the degree of emission limitation determined by the EPA . . .'' to the state demonstrating that ''the facility cannot reasonably achieve the degree of emission limitation determined by the EPA. . . .'' At proposal, the EPA explained that ''the state must show that implementing the BSER is not reasonable for the designated facility due to fundamental differences between the factors the EPA considered in determining the BSER, such as cost and technical feasibility of control and circumstances at the designated facility.'' [107] However, it is not sufficient that a facility not be able to implement the BSER; the state must demonstrate that the facility cannot otherwise reasonably achieve the EPA's degree of emission limitation (for example, through a different system of emission reduction) in order for a facility to be eligible for a less stringent standard of performance. This is consistent with the definition of ''standard of performance'' in CAA section 111(a)(1), which is a ''standard for emissions of air pollutants'' that ''reflects the degree of emission limitation achievable through application of the [BSER],'' as opposed to a standard requiring the application of the BSER. That is, the statute requires a certain degree of emission limitation, not the use of a particular technology. Therefore, the fact that a facility cannot apply the BSER on its own is not sufficient to invoke RULOF.

The EPA believes that simplifying the language in 40 CFR 60.24a(e) will reduce confusion about the ultimate circumstances under which invoking RULOF is appropriate: where a particular facility cannot meet the degree of emission limitation determined by the EPA. Because the degree of emission limitation is based on the EPA's BSER determination, the information the EPA considered in determining the BSER remains the touchstone for determining when a particular facility cannot reasonably achieve the degree of emission limitation in the applicable emission guideline. Furthermore, given that the BSER presumptively reflects a system that is adequately demonstrated and reasonable for all designated facilities within a source category or subcategory, the EPA anticipates that in many if not most instances a state considering RULOF will in fact be evaluating the reasonableness of applying the BSER to achieve the degree of emission limitation. However, even if the state is evaluating the use of a different system to achieve the degree of emission limitation determined by the EPA, the factors and information the EPA considered in the EG, *e.g.,* cost effectiveness, will remain relevant to this inquiry.

As a corollary to this change, the EPA is not finalizing the provision proposed at 40 CFR 60.24a(g), which would have provided that a state could not apply a less stringent standard of performance where a facility could reasonably

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[103] 87 FR 79199.

[104] 84 FR 32520, 32577 (July 8, 2019).

[105] Memorandum, ''Redline/Strikeout for proposed amendments to 40 CFR 60 Subpart Ba: Adoption and Submittal of State Plans for Designated Facilities,'' Docket ID No, EPA–HQ–OAR–2021–0527–0035.

[106] See 40 CFR 60.24(f).

[107] 87 FR 79199.

implement a system of emission reduction other than the BSER to achieve the degree of emission reduction determined by the EPA. This provision is redundant now that the EPA is clarifying in 40 CFR 60.24a(e) that states may apply less stringent standards of performance only when they demonstrate that a facility cannot reasonably achieve the degree of emission limitation determined by the EPA.

Both subpart B at 40 CFR 60.24(f) and the existing regulations of subpart Ba at 40 CFR 60.24a(e) provide that use of RULOF is appropriate if a state demonstrates that one of the three circumstances is met ''with respect to each facility (or class of such facilities).'' In the notice of proposed rulemaking for this action, the EPA stated that, ''[t]o the extent that a state seeks to apply RULOF to a class of facilities that the state can demonstrate are similarly situated in all meaningful ways, the EPA proposes to permit the state to conduct an aggregate analysis of [the five BSER factors] for the entire class.'' [108] The EPA is reiterating in this final rule that invoking RULOF and providing a less-stringent standard or performance or longer compliance schedule for a class of facilities is only appropriate where all the facilities in that class are similarly situated in all meaningful ways. That is, they must not only share the circumstance that is the basis for invoking RULOF, they must also share all other characteristics that are relevant to determining whether they can reasonably achieve the degree of emission limitation determined by the EPA in the applicable EG. For example, it would not be reasonable to create a class of facilities for the purpose of RULOF on the basis that the facilities do not have space to install the EPA's BSER control technology if some of them are able to install a different control technology to achieve the degree of emission limitation in the EG. Similarly, it would not be appropriate for a state to conduct a single evaluation pursuant to 40 CFR 60.24a(f) to apply the same less stringent standard of performance to a class of facilities if individual facilities within that class have different characteristics that could result in different standards of performance. The evaluation of when it is appropriate to create a class of facilities is extremely source-sector and EG-specific; the EPA will address circumstances in which it may or may not be permissible to group facilities for purposes of RULOF in individual EGs.

In summary, the EPA is finalizing its proposed revisions to 40 CFR 60.24a(e) with additional clarifications. The first is to reflect that the ''fundamentally different'' standard applies to all three circumstances for invoking RULOF. This clarification reinforces that invocation of RULOF is appropriate when the circumstances of a particular designated facility are fundamentally different from those the EPA considered such that the facility cannot reasonably achieve the degree of emission limitation the EPA determined pursuant to CAA section 111(a)(1). Second, the EPA is revising the circumstances under which invoking RULOF is appropriate from a demonstration that a facility cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA to a demonstration that the facility cannot reasonably achieve the degree of emission limitation determined by the EPA. This change is intended to simplify and clarify the provision as it is the degree of emission limitation determined by the EPA, not the system used to achieve it, that has always been the relevant consideration under CAA sections 111(d) and 111(a)(1). Third, the EPA is clarifying the provision that states may use RULOF to provide for a longer compliance timeline as well as less-stringent standards of performance, which was inadvertently omitted from the proposed regulatory text. In general, the EPA is revising 40 CFR 60.24a(e) to provide more objective and consistent criteria for when it is appropriate to invoke RULOF in order to guide states in applying standards of performance to particular designated facilities and the EPA in evaluating state plans. The EPA is not finalizing proposed 40 CFR 60.24a(g), as this provision is now superfluous given the updates to 40 CFR 60.24a(e).

The EPA acknowledges that what is considered reasonable in light of the statutory factors is a fact-specific inquiry based on the source category and pollutant that is being regulated pursuant to a particular EG, and that the EPA cannot anticipate and address all circumstances that may arise in these general implementing regulations. Thus, the EPA may consider additional factors and establish additional parameters governing the consideration of RULOF, including what deviations from the EPA's determinations may be within the range of reasonable versus deviations that constitute fundamental differences between facility-specific circumstances and the EPA's degree of emission limitation determination, in a particular EG.

b. Calculation of a Standard Which Accounts for Remaining Useful Life and Other Factors

If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that there is a fundamental difference between the information the EPA considered in the applicable EG and the information specific to a particular source that makes it unreasonable for that source to achieve the degree of emission limitation, the state may then apply a less stringent standard of performance.[109] The current RULOF provision, 40 CFR 60.24a(e), does not specify how a less stringent standard is to be calculated and applied. While this provision stands on its own and permits states to consider RULOF to apply a less stringent standard of performance, the lack of a process for determining any such standards makes it difficult for states to know whether the result will be approvable and additionally makes it difficult for the EPA to review less stringent standards in a consistent and equitable manner. In order to provide clarity and ensure the integrity of the emission reduction purpose of CAA section 111(d), as well as to ensure the equitable treatment of designated facilities across states, the EPA is promulgating a framework in 40 CFR 60.24a(f) for the calculation of a standard of performance that accounts for RULOF. As explained in this section of the preamble, the process the EPA is finalizing differs from the proposed framework, but the material components of calculating and applying a less stringent standard of performance, and the underlying purpose and direction of the EPA's framework, remain the same.

The EPA proposed to require that states determine a source-specific BSER for each designated facility for which RULOF has been invoked pursuant to 40 CFR 60.24a(e) and include a standard of performance that reflects the degree of emission limitation achievable through application of that BSER in their state plans. The notice of proposed rulemaking explained that the statute requires the EPA to determine the BSER by considering emission control methods that it finds to be adequately demonstrated, and then determining which is the best system of emission

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[108] 87 FR 79200 n.46.

[109] States intending to apply a less-stringent standard of performance pursuant to RULOF would include all information, demonstrations, etc. necessary to satisfy 40 CFR 60.24a(e) through (h) in their state plan submissions. The EPA will first review a state's demonstration that invocation of RULOF pursuant to 40 CFR 60.24a(e) is appropriate for a particular designated facility against the applicable requirements. If the EPA finds that demonstration satisfactory, it will proceed to evaluate the standard of performance for that facility applied pursuant to 40 CFR 60.24a(f).

reduction by evaluating (1) the cost of achieving such reduction, (2) nonair quality health and environmental impacts, (3) energy requirements, and (4) the amount of reductions.[110] To be consistent with this statutory construct, the EPA proposed to require that in determining a source specific BSER for a designated facility (or class of such facilities [111]), a state must also consider all these factors in applying RULOF for that source.

Specifically, the EPA proposed that a state in its plan submission would identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same factors and evaluation metrics as the EPA did in developing the EG. For example, if the EPA evaluated the cost factor using the evaluation metric of capital costs in determining the BSER, the EPA proposed that the state must do the same in evaluating a control technology for an individual designated facility, rather than selecting a different evaluation metric for cost. The state would then calculate the emission reductions that applying the source-specific BSER would achieve and select the standard of performance which reflects this degree of emission limitation. This standard would be in the form or forms (*e.g.,* numerical rate-based emission standard) as required by the specific EG.

While the EPA proposed to require that states identify all control technologies or other systems of emission reduction available for the source and evaluate each system using the same factors and evaluation metrics as the EPA did in determining the BSER, it also solicited comment on whether there are additional factors, not already accounted for in the BSER analysis, that the EPA should permit states to consider in determining a less stringent standard of performance. The EPA further solicited comment on whether it should provide that the manner in which the EPA conducted the BSER analysis would be a presumptively approvable framework for applying a less-stringent standard rather than requirements and, if so, what different approaches states might use to evaluate and identify less stringent standards of performance.

The EPA also noted at proposal that CAA section 111(d) requires that state plans include measures that provide for the implementation and enforcement of a standard of performance. This requirement applies to any standard of performance established by a state, including one that accounts for RULOF. Such measures include monitoring, reporting, and recordkeeping requirements, as required by 40 CFR 60.25a, as well as any additional measures specified under an applicable EG. In particular, any standard of performance that accounts for RULOF is also subject to the requirement under subpart Ba that the state plan submission include a demonstration that each standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable. 40 CFR 60.27a(g)(3)(vi). The EPA did not reopen these existing requirements of subpart Ba in this rulemaking.

The EPA received both comments in support of and comments opposed to the proposed requirements for calculating facility-specific standards of performance under RULOF. Some commenters supported the addition of a regulatory framework for facility-specific BSER analysis and stated that the BSER factors encompass all relevant information to a state's determination of an appropriate standard for a facility. Other commenters opposed the proposed framework. Comments in opposition largely fell into two categories: Some commenters asserted there is no basis in the statute for requiring states to conduct facility-specific BSER analyses pursuant to RULOF and, relatedly, that the EPA should not put restrictions on what states may consider in applying a less stringent standard of performance for a particular source but should rather maintain the wide latitude afforded to states under CAA section 111. Others stated that the EPA's proposed requirements would constitute a heavy lift for state agencies and would require substantial work for states to implement. In this vein, one commenter requested that the EPA not require states to evaluate, as part of their facility-specific BSER analyses, control technologies that the Agency has previously excluded from the BSER on the basis of technological or economic feasibility. Rather, the only control technologies that states should be required to evaluate are technologies that result in less emission reduction than the technology the EPA determined to be the BSER.

As explained below, the EPA disagrees with comments that there is no basis for putting a framework in place for states and the Agency to use in applying and evaluating less stringent standards of performance. The EPA believes that such a framework is well supported by the statutory purpose, text, and context of the RULOF provision. In particular, after considering the comments, the EPA believes that the purpose, text, and context support a requirement that states (or the EPA in the case of a Federal plan) calculate and apply a standard of performance that varies from the EPA's degree of emission limitation in the applicable emission guideline only to the extent necessary to address the fundamental difference that is the basis for invoking RULOF.

First, providing a framework for calculating less stringent standards of performance is consistent with the text of CAA section 111(d) and is responsive to Congress's directive in that provision that the Agency prescribe regulations establishing a procedure for state plans, including regulations that ''permit'' states ''in applying'' a standard of performance to a particular source to ''take into consideration'' RULOF. The provisions the EPA is promulgating in this action set out a procedure—the series of steps and considerations states must undertake to apply a less stringent standard of performance. As described in section III.E.2. of this preamble, to ''permit'' something means to allow or give consent for that thing to occur. In this case, the EPA is prescribing the procedures that allow for states to apply less stringent standards of performance. To ''apply'' means ''to put to a special use or purpose'' or ''put into practical operation,'' [112] and ''consideration'' means ''the action of taking into account.'' [113] Thus, the state's authorization to ''apply[]'' a standard of performance to any particular source, ''tak[ing] into consideration'' RULOF, means the state may particularize a standard of performance for a given source by accounting for remaining useful life and other factors where there are fundamental differences between the information specific to a facility and the information the EPA considered in determining the degree of emission limitation achievable through application of the BSER. In doing so, the state must remain as consistent as possible with that degree of emission limitation in light of what the Supreme

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[110] The D.C. Circuit has stated that in determining the ''best'' system, the EPA must take into account ''the amount of air pollution'' reduced, *see Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981), and the role of ''technological innovation.'' *Id.* at 347.

[111] See section III.E.3.a. of this preamble. The EPA expects to address the appropriateness of invoking RULOF and applying less-stringent standards to a class of facilities in individual EGs.

[112] Oxford English Dictionary, *https://www.oed.com/search/advanced/Meanings?textTermText0=apply&textTermOpt0=WordPhrase,* last accessed Nov. 1, 2023.

[113] *Id., https://www.oed.com/search/advanced/Meanings?textTermText0=consideration&textTermOpt0=WordPhrase,* last accessed Nov. 1, 2023.

Court has recognized as the EPA's ''primary regulatory role in section 111(d)'' [114] and the emission reduction purpose of CAA section 111.

Second, the history and context of CAA section 111(d) supports the EPA's authority to provide a framework for states' consideration of RULOF. As explained in section III.E.2. of this preamble, the standards of performance that states establish in state plans must generally be no less stringent than the degree of emission limitation that Congress required, which is the degree of emission limitation that EPA determines in the applicable EG.[115] However, in the original 1975 subpart B implementing regulations, the EPA allowed states to grant variances from this degree of emission limitation in cases of economic hardship based on the age of the plant and other factors, as long as the states could justify the variances.[116] Congress then, in the 1977 CAA Amendments, included the RULOF provision in CAA section 111(d)(1), which similarly allows states to deviate from the EPA's degree of emission limitation based on consideration of an existing source's age (*i.e.,* remaining useful life) and other factors.

Congress's inclusion of the RULOF provision in CAA section 111(d)(1) should be interpreted as expressing its intent to confirm that the EPA has authority to promulgate a regulatory variance provision, including the provision the EPA had, at that time, recently promulgated. The EPA, following its 1974 proposal of the subpart B implementing regulations, had received a comment arguing that it did not have authority to promulgate such a variance provision, to which it responded by asserting that it did have the authority and explaining that such a provision is consistent with CAA section 111(d).[117] The Courts have held that Congress is presumed to be aware of an administrative interpretation under certain circumstances.[118] Accordingly, Congress's adoption of the RULOF provision in the 1977 CAA Amendments should be interpreted as expressing its intent to make explicit under CAA section 111(d) the EPA's authority to promulgate regulations that include a variance provision.[119]

It is also clear that the EPA understood the RULOF provision in CAA section 111(d)(1) to be a variance in the same way it had provided a variance in subpart B. This is evidenced by the fact that following the 1977 CAA Amendments the EPA did not revise its 1975 regulations, which were premised on this understanding, for over forty more years.[120] This indicates that the EPA viewed its 1975 regulations granting a variance as authorized under the RULOF provision enacted in 1977.

The regulations the EPA is promulgating at 40 CFR 60.24a(f) are consistent with the long-held view that the Agency's implementing regulations provide a variance. While 40 CFR 60.24a(e) provides the process for invoking this variance, to date the regulations have not included the second part: how to address a source that has qualified for the variance.[121] Although variances may operate in different ways in the context of different statutory and regulatory schemes, it is clear from both the language and the context of the RULOF provision that Congress intended it to provide for alternative compliance with CAA section 111(d), *i.e.,* a less stringent standard of performance, to the extent necessary to address the fundamental differences between the EPA's EG and the circumstances of a particular facility. Such variances are common throughout environmental statutes and, for the environmental protection aim to be achieved, must be crafted so that the alternative is as close as possible to the statutory standard, even as it departs from the generally applicable requirement.

For example, Clean Water Act (CWA) section 301(b)(2) requires, in part, certain sources to achieve effluent limitations consistent with application of the best available technology economically achievable, which will result in reasonable further progress toward eliminating the discharge of all pollutants. These limitations must be determined in accordance with factors specified in the statute and are provided by either effluent limitation guidelines issued by the EPA or the permitting authority on a best professional judgment basis where no such national effluent limitation guidelines exist. CWA section 301(n) authorizes the EPA to grant variances for existing sources from the best available technology requirements of its effluent limitation guidelines where a facility can demonstrate that it is fundamentally different with respect to the factors (other than cost) specified in the statute and considered by the EPA in establishing those requirements. CWA section 301(n) further requires that, where a variance is warranted, the EPA must provide an alternative requirement that (1) is no less stringent than justified by the fundamental difference, and (2) will not result in a non-water quality environmental impact which is markedly more adverse than the impact considered in establishing the rule.[122]

Similarly, section 3004(m)(1) of the Resource Conservation and Recovery Act (RCRA) requires the EPA to promulgate regulations specifying the levels or methods of treatment of hazardous waste, if any, that ''substantially diminish the toxicity of the waste or substantially reduce the

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[114] *West Virginia* v. *EPA,* 142 S. Ct. at 2601.

[115] 40 CFR 60.24(c); 40 CFR 60.24a(c); see 39 FR 36102.

[116] 40 CFR 60.24(f); 40 FR 53344.

[117] 40 FR 53344.

[118] See *Lorillard* v. *Pons*, 434 U.S. 575, 580 (1978) (''Congress is presumed to be aware of an administrative or judicial interpretation of a statute and to adopt that interpretation when in re-enacts a statute without change.'').

[119] In the notice of proposed rulemaking for this rule, the EPA stated that ''[t]here are noticeable differences between the subpart B variance provision and the CAA section 111(d) RULOF provision that indicate Congress did not intend to incorporate and ratify all aspects of the EPA's regulatory approach when amending CAA section 111(d) in 1977.'' The EPA thus proposed to conclude that it could not ''clearly ascertain whether the statutory RULOF provision ratified the variance provision under subpart B . . . .'' 87 FR 79176, 79205 (Dec. 23, 2022). Upon further consideration, however, the EPA believes the most reasonable interpretation of the statutory RULOF provision, given its history and context, is that Congress intended it to authorize the EPA to provide variances from the required degree of emission limitation on a case-by-case basis. However, the EPA agrees with its assessment at proposal that Congress did not necessarily incorporate or ratify specific aspects of the Agency's 1975 variance provision; it is reasonable that Congress would not have codified the precise regulations that the EPA promulgated in 1975 and instead leave the Agency space to revise those regulations as needed, as it is did in 2019 and is doing in the present rule.

[120] The ACE rule, in which the EPA promulgated subpart Ba in 2019, declined to refer to the RULOF provision as a ''variance,'' apparently because the term conflicted with that rule's view that RULOF would be used to establish standards of performance as a general matter. 84 FR 32520,32570 n. 291 (July 8, 2019). The ACE rule misunderstood the RULOF provision. As explained throughout section III.E. of this preamble, this provision authorizes a state to depart from the degree of emission limitation the EPA determines under CAA section 111(a)(1) when applying a standard of performance to a particular source pursuant to consideration of RULOF. As the 1975 regulations indicated, 40 FR 53332, 53344 (Nov. 17, 1975), it is appropriate to call this type of departure or exception a ''variance.''

[121] The EPA explains the reasons it believes it is now necessary to provide the second part of the process for this variance—how to calculate a less stringent standard of performance—in section III.E.2. of this preamble.

[122] As another example, CWA section 301(c) provides that the EPA may modify the best available technology requirements for particular sources if a facility can demonstrate that a modified standard will (1) represent the maximum use of technology within the economic capability of the owner or operator and (2) will result in reasonable further progress toward the elimination of the discharge pollutants.

likelihood of migration of hazardous constituents from the waste so that short-term and long-term threats to human health and the environment are minimized.'' The EPA has set generally applicable regulatory standards for the treatment of hazardous waste under RCRA section 3004(m)(1). The Agency has also has provided regulatorily for waste-specific variances in instances in which it is not physically possible, or it is inappropriate, to treat waste to the level specified in the Agency's treatment standard or to treat waste using the method the Agency specified as the treatment standard.[123] In order for the EPA to grant a variance, the party requesting it must provide an alternative waste treatment requirement that is sufficient to minimize threats to human health and the environment posed by disposal of the waste, *i.e.,* that is sufficient to satisfy the underlying statutory requirement, even though it differs from the generally applicable treatment standard prescribed by the EPA.

The discussion above highlights examples of environmental statutes that require adherence to a generally applicable standard, but under which either Congress or the EPA has authorized variances when it is impossible or unreasonable for a particular regulated entity to achieve that standard. For a general statutory standard requiring the ''best'' technology or ''substantial'' progress, the variances are an alternative way of achieving the statutory standard, as opposed to an exemption from that standard. In the case of the CWA variances, in particular, this means that the alternative requirement pursuant to the variance constitutes a degree of pollutant limitation that deviates as little as possible from the EPA's regulation pursuant to that statutory standard. That is, the alternative requirement constitutes a particular regulated entity's best effort to achieve the generally applicable standard.

The EPA has crafted 40 CFR 60.24a(e) and (f) to be a variance in the same vein as the CWA and RCRA statutory and regulatory provisions discussed above. It is clear from both the history and plain language of CAA section 111(d)(1) that Congress did not provide an exemption from regulation, but rather a method for providing alternative compliance with the general statutory requirement of that section.[124] CAA section 111(d) provides that states must submit plans that include ''standards of performance,'' and CAA section 111(a)(1) defines ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the Administrator determines has been adequately demonstrated.'' Thus, the underlying statutory standard is the degree of emission limitation determined by the EPA in the applicable EG. A variance from this statutory standard is not available if a source can reasonably achieve the EPA's degree of emission limitation. If a variance is warranted, the alternative requirement, *i.e.,* a standard of performance pursuant to consideration of RULOF, must be a standard for emissions of air pollutants that is no less stringent than necessary to address the fundamental differences identified under 40 CFR 60.24a(e). That is, the degree of emission limitation of a standard of performance pursuant to RULOF must deviate as little as possible from the degree of emission limitation in the applicable EG.[125] Consistent with the structure of CAA section 111(d) generally, the RULOF provision does not prescribe the use of any particular system of emission reduction in conjunction with a less stringent standard of performance but instead focuses on ensuring that the degree of emission limitation deviates no more than necessary; anything less would be inconsistent with the general statutory framework.

Thus, 40 CFR 60.24a(f)(1) requires that a less stringent standard of performance be no less stringent (or have a compliance schedule no longer) than necessary to address the fundamental differences identified under 40 CFR 60.24a(e). It also contains a framework that states must use, to the extent necessary to satisfy that criterion, to determine the less stringent standard of performance. In some instances, determining the standard of performance that is no less stringent than necessary to address the fundamental differences will be straightforward and the state will not need to undertake the analysis of additional systems of emission reduction that is laid out in the second and third sentences of 40 CFR 60.24a(f)(1). For example, where the BSER the EPA has identified in the applicable EG may be implemented at the source at either a lower stringency or with a longer compliance schedule and it is clear that no other system of emission reduction will result in greater stringency or a shorter schedule, it is unnecessary for a state to evaluate other systems in order to satisfy the first sentence of paragraph (f)(1). In this case, the state would simply justify the degree of emission limitation or compliance schedule as the most stringent or shortest reasonably possible.

However, where a particular source cannot implement the types of controls that comprise the BSER or where it is not apparent that implementation of the BSER at lower stringency or with a longer compliance schedule will result in a standard of performance that is no less stringent than necessary, evaluation of additional systems of emission reduction will be necessary under 40 CFR 60.24a(f)(1). In this situation, the EPA does not believe it is reasonably possible to determine a standard of performance that satisfies the criterion of § 60.24a(f)(1) without considering the systems of emission reduction that the EPA determined, in the applicable EG, have been adequately demonstrated.[126] As discussed below, however, it may not be necessary for a state to evaluate every system of emission reduction that the EPA considered. Thus, the EPA is requiring that, to the extent necessary to determine a standard of performance that is no less stringent than necessary, states must evaluate the systems of emission reduction in the applicable EG. As further discussed below, the EPA expects states will leverage the information and analysis the Agency has provided in that EG for their evaluations, particularizing that information to the circumstances of the particular facility as needed.

Similarly, it is not reasonably possible to craft a standard of performance that is no less stringent than necessary to address a fundamental difference between a particular facility's circumstances and the information the EPA considered in determining the degree of emission limitation without engaging with that information.[127] In

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[123] 40 CFR 268.44.

[124] See CAA section 111(d)(1) (requiring that states considering RULOF for a particular source nonetheless apply a standard of performance to that source); 39 FR 36102, 36102 (Oct. 7, 1974) (proposed regulations ''provide that States may establish less stringent emission standards on a case-by-case basis provided that sufficient justification is demonstrated in each case'').

[125] Cf. *Weyerhauser Co.* v. *Costle,* F.2d 1011, 1035 (D.C. Cir. 1978) (Clean Water Act variance provision ''authorizes the Agency to relieve a particular point source operator from any demands that the Act does not allow the Agency to make of the industry generally.'' However, the point source operator must still, consistent with the general statutory requirement for the industry, use the best available technology economically available and ''the variance may not halt progress toward eliminating pollution.'').

[126] See 40 CFR 60.22a(b)(2).

[127] Cf. *Weyerhauser Co.* v. *Costle,* F.2d 1011, 1035 (D.C. Cir. 1978) (CWA section 304(b)(2)(B) lays out

determining the degree of emission limitation in an EG, the EPA considers whether available systems of emission reduction have been adequately demonstrated, the amount of emissions they reduce, the cost of achieving such reduction, any nonair quality health and environmental impacts, and energy requirements.[128] To evaluate whether a state's less stringent standard of performance is no less stringent than necessary, both states and the EPA need to be able to compare the information relevant to the source category (or subcategory) with the facility-specific information. Additionally, to ensure equitable consideration and treatment of sources in different states that have invoked RULOF to apply less stringent standards of performance, it is necessary that each state is using a common set of factors and metrics as the bases for their decisions. Using the factors [129] and evaluation metrics [130] that the EPA considered in determining the degree of emission limitation ensures ''apples-to-apples'' comparisons, both between the EPA's degree of emission limitation and a state's less stringent standard of performance and between different sources in different states. Thus, to the extent that states are evaluating systems of emission reduction to determine a less stringent standard of performance under 40 CFR 60.24a(f)(1), they must use the same factors the EPA considered, and the evaluation metrics the EPA used to consider the factors, in doing so.

For example, assume the EPA considered cost using the evaluation metric dollars per ton of pollutant reduced and concluded that costs of up to $500/ton of pollutant reduced are reasonable. A state has invoked RULOF for a particular source under 40 CFR 60.24a(e) because, based on that source's shortened remaining useful life, the cost, in dollars per ton of pollutant reduced, of achieving the degree of emission limitation in the applicable EG is fundamentally different from $500/ton. The state, in determining a less stringent standard of performance pursuant to 40 CFR 60.24a(f), must evaluate the systems of emission reduction in the EG using the cost evaluation metric dollars per ton of pollutant reduced. In doing so, the state would consider the reasonableness of the costs of those systems against the benchmark of $500/ton.

The regulations at 40 CFR 60.24a(e) also allow states to invoke RULOF based on a fundamental difference unrelated to cost, *e.g.,* physical impossibility of implementing control equipment necessary to achieve the EPA's degree of emission limitation. In this instance, a state may find that a particular facility's footprint is such that there are no systems of emission reduction that could be installed at the facility to achieve the degree of emission limitation in the applicable EG. Under 40 CFR 60.24a(f)(1), the state would evaluate the systems of emission reduction in the EG using the factors—technical feasibility, amount of emission reductions, cost of achieving such reductions, nonair quality health and environmental impacts, and energy requirements—and evaluation metrics the EPA considered in order to determine the standard of performance that is both physically possible for the source to achieve and that is no less stringent than necessary.

As explained in section III.E.3.a., there may be facility-specific circumstances and factors that the EPA did not anticipate and consider in the applicable EG that make achieving the EPA's degree of emission limitation unreasonable for that facility. Such facility-specific information may constitute an ''other factor specific to the facility'' under 40 CFR 60.24a(e) and could potentially represent a fundamental difference between the information the EPA considered in determining the degree of emission limitation and the information specific to a facility. Such facility-specific ''other factors'' may also be relevant in determining and applying a less stringent standard of performance. Thus, pursuant to the process the EPA is finalizing in 40 CFR 60.24a(f)(1), states may consider ''other factors specific to the facility'' that were the basis of the demonstration under paragraph (e) in determining and applying a less stringent standard of performance.

In some instances, the fundamental difference between the information the EPA considered in the applicable EG and the information specific to a facility will manifest as a difference in whether or how an enumerated factor applies to a particular facility. For example, parasitic load may be an appropriate evaluation metric for considering energy requirements for some systems of emission reduction but not for others, or water availability may not have been important to the EPA's consideration of nonair quality environmental impacts but may be relevant for a source located in a particularly water-scarce region. If such information represents a fundamental difference that make the EPA's degree of emission limitation determination unreasonable for a particular facility pursuant to 40 CFR 60.24a(e), it would be reasonable and permissible for a state to consider such information in applying a less stringent standard of performance under 40 CFR 60.24a(f)(1).

In addition to ''other factors'' that the EPA did not necessarily consider, there may be circumstances in which a system of emission reduction that the EPA did not consider in the applicable EG or that the EPA concluded was not adequately demonstrated because, *e.g.,* it is not available on a source-category wide basis, is available, technically feasible, and potentially reasonable for a particular facility.

The EPA is therefore providing in 40 CFR 60.24a(f)(1) that states may consider, in determining a less stringent standard of performance, ''other factors specific to a facility'' that were the basis for the fundamental difference and invoking RULOF under 40 CFR 60.24a(e), as well as systems of emission reduction in addition to those the EPA considered in the applicable EG. At the same time, however, the EPA in a particular EG makes certain judgments about which systems are available and adequately demonstrated, as well as how the factors are reasonably considered when evaluating those systems for designated facilities within the source category. To ensure that any additional considerations do not result in a standard of performance that deviates more than necessary from the

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the minimum factors the EPA must consider in determining the best available technology economically achievable on a source-category basis. In deciding whether a variance sought by a particular point source owner represents the ''maximum use of technology within the economic capability of (that) owner, the permit-granting agency, and the EPA in supervising that agency, must consider the factors laid out in section 304(b)(2)(B).'').

[128] The D.C. Circuit has stated that in determining the ''best'' system of emission reduction, the EPA must also take into account the role of ''technological innovation.'' See *Sierra Club* v. *Costle*, 657 F.2d 298, 347 (D.C. Cir. 1981). However, because technological innovation is less likely to be relevant at the scale of a single facility than it is on a source-category basis, the EPA is not explicitly requiring states to consider it under 40 CFR 60.24a(f)(1).

[129] Under 40 CFR 60.24a(f)(1), as finalized in this action, states must evaluate the systems of emission reduction identified in the applicable EG. The EPA's EGs include systems of emission reduction that have been ''adequately demonstrated.'' There is therefore no need for states to revisit the ''adequately demonstrated'' consideration. However, ''adequately demonstrated'' includes ''technical feasibility'' and the EPA acknowledges that systems of emission reduction that are adequately demonstrated for the source category may not be technically feasible for a particular source. The EPA is thus adding ''technical feasibility'' to the list of factors states must consider in determining a less stringent standard of performance.

[130] An ''evaluation metric'' includes both the form of the EPA's consideration of a factor and any threshold or level of reasonableness the EPA considered in the applicable EG.

EPA's degree of emission limitation, the state must justify how any additional consideration results in a standard of performance that is no less stringent than necessary to address the fundamental differences identified under paragraph (e).

In addition to being consistent with statutory and regulatory precedent on variances, the procedure the EPA is promulgating in 40 CFR 60.24a(f)(1) for determining standards of performance that are no less stringent than necessary is also consistent with CAA section 111. As explained throughout this section of the preamble, CAA section 111(a)(1) defines a standard of performance as a standard for emissions of air pollutants that reflects a certain degree of emission limitation and gives the EPA the ''primary regulatory role'' [131] of determining that degree of emission limitation. Congress required that, in doing so, the EPA evaluate systems of emission reduction that have been adequately demonstrated and determine which is best based on the amount of emission reductions, cost of achieving such reduction, nonair quality health and environmental impacts, and energy requirements. As also explained in this section of the preamble, CAA section 111(d) directs the EPA to prescribe regulations that ''permit'' states ''in applying'' a standard of performance to a particular source to ''take into consideration'' RULOF. The requirements the EPA is promulgating in 40 CFR 60.24a(f)(1) ''permit'' a state to particularize a standard of performance for any given source by accounting for RULOF where there are fundamental differences between the information specific to a facility and the information the EPA considered in determining the degree of emission limitation in the applicable EG. In doing so, the state must remain as consistent as possible with that degree of emission limitation in light of what the Supreme Court has recognized as the EPA's primary regulatory role in CAA section 111(d) and the emission reduction purpose of CAA section 111. Because Congress has identified the factors noted above as relevant considerations for the EPA in determining a standard of performance, the Agency believes it is also reasonable to require states to consider these systems, factors, and evaluation metrics in the manner that the EPA did in applying standards of performance pursuant to 40 CFR 60.24a(f).

Furthermore, the EPA's authority to promulgate 40 CFR 60.24a(f) is buttressed by CAA section 111(d)(2). As discussed in sections III.E.1. and 2. of this preamble, CAA section 111(d)(2) provides that the EPA shall have the same authority as under CAA section 110(c) to prescribe a Federal plan where a state fails to submit a satisfactory plan. The EPA's long-standing interpretation of this subsection is that it provides the Agency authority to substantively review states' standards of performance.[132] The existing regulations of subpart Ba and the EPA's emission guidelines provide the substantive criteria for the Agency's evaluation of standards of performance generally; [133] the regulations the EPA is promulgating at 40 CFR 60.24a(f) constitute the substantive criteria for evaluating standards of performance states have applied pursuant to RULOF.

Some commenters on proposed 40 CFR 60.24a(f) dislike the EPA's approach to determining what constitutes a ''satisfactory'' less stringent standard of performance but offer no alternatives, other than states should have complete discretion to apply standards pursuant to RULOF. This cannot be correct. If this was the case, the EPA would have no choice but to approve plans in which states have applied business-as-usual standards, or standards that allows designated facilities' emissions to *increase,* even if more stringent standards of performance are reasonable for that facility. Such an outcome would be inconsistent with the text, context, and purpose of CAA section 111. The EPA believes the criteria it is providing for the Agency's substantive review of less stringent standards of performance are a reasonable approach to fulfilling its statutory obligation under CAA section 111(d)(2) to substantively review standards of performance in state plans.

Moreover, it is not uncommon for the EPA to promulgate regulatory frameworks to guide states in areas in which Congress has granted them discretion. For example, under the visibility protection provisions of CAA section 169A, Congress directed the EPA to promulgate regulations to assure that reasonable progress towards meeting the national goal for visibility improvement in mandatory class I Federal areas, as well as to assure compliance with the requirements of CAA section 169A. Section 169A further provides that states implement the visibility protection requirements through state implementation plans, in which they must include emission limitations for sources of visibility impairing pollutants. The statute provides two types of control analyses for states to use in determining the applicable emission limitations: reasonable progress and best available retrofit technology.[134] Although Congress directed states to determine the best available retrofit technology for their existing sources, the EPA, in promulgating its implementing regulations, provided a detailed methodology and requirements for doing so in 40 CFR 51.308(e) and 40 CFR part 51, appendix Y. The EPA has similarly prescribed requirements for states to determine the emission reduction measures that are necessary to make reasonable progress in 40 CFR 51.308(f).[135] These requirements create procedural and substantive frameworks within which states exercise their discretion in order to ensure the outcomes of their control analyses are consistent with the statutory requirements and purpose. The regulatory framework and associated guidance also provide states useful clarity as to how the EPA will fulfill its statutory obligation to review and approve or disapprove state plans, and how the EPA will promulgate Federal plans.

The EPA is not providing that states can forgo analyzing control technologies or other systems of emission reduction that the EPA has excluded from being the BSER on the basis of technological or economic feasibility, as suggested by commenters. The EPA conducts BSER analyses on a source-category basis. It may be that a system of emission

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[131] *West Virginia* v. *EPA*, 142 S. Ct. at 2601.

[132] See 40 FR 53342 (CAA section 111(d)'s references to CAA section 110 suggest that Congress intended the Administrator to apply some substantive criterion to his review of State plans).

[133] See 40 CFR 60.24a(c).

[134] CAA section 169A(g)(1) and (2). The statutory factors that states must use to determine reasonable progress are ''costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements.'' The statutory factors for best available retrofit technology analysis are: ''costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.''

[135] The EPA has also issued extensive and detailed guidance for states in conducting reasonable progress analyses for sources of visibility impairing pollutants. See Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (2019), available at *https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period;* Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (2021), available at *https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation.*

reduction is generally adequately demonstrated but is not the BSER because it cannot be applied to designated facilities across the category at a reasonable cost or because it is technically infeasible for a certain portion of the category. However, designated facilities that are eligible to receive a less-stringent standard of performance are in demonstrably different circumstances than facilities in the source category generally. Therefore, control technologies or other systems that may not be the BSER for the source category may be reasonable for a source that has invoked RULOF. Similarly, to avoid inadvertently precluding consideration of a system that could allow a state to apply a standard of performance that is no less stringent than necessary, the EPA is not providing that states must consider only control technologies or systems that result in less emission reductions than the EPA's BSER. While it is true that states should only be in the position of applying less stringent standards of performance if they have demonstrated that a designated facility cannot achieve the degree of emission limitation, there may be situations in which it is not practical or feasible to ascertain *a priori* what degree of emission limitation a technology or system could achieve when applied to a particular source. Thus, the EPA does not believe it is reasonable to narrow the scope of control technologies or other systems of emission reduction that states must consider under these general implementing regulations. The Agency may find it appropriate to do so in the context of an individual EG.

Some commenters noted the resources and potential burden associated with conducting the proposed source-specific BSER analyses. While the EPA is not finalizing a requirement for states to conduct source-specific BSER analyses, it acknowledges that stakeholders could have similar concerns in the context of the provision being promulgated at 40 CFR 60.24a(f). However, the EPA does not believe the RULOF provisions will significantly add to states' planning processes. First, as explained in section III.E.2. of this preamble, consistent with the statutory framework the EPA believes that use of RULOF should be an exception to the general rule that the EPA's degree of emission limitation is reasonable for designated facilities within the applicable source category. Given the EPA's ability to subcategorize source categories and to tailor its EG to the circumstances of each subcategory, using RULOF to apply a less stringent standard of performance should be appropriate in only very limited circumstances.

Second, as explained above, the EPA is providing in 40 CFR 60.24a(f)(1) that states must evaluate the systems of emission reduction in the applicable EG using the factors and evaluation metrics the EPA considered ''[t]o the extent necessary to determine a standard of performance'' that is no less stringent than necessary to address the fundamental differences identified under paragraph (e). As noted above, the EPA anticipates that in some if not many cases, states will be able to demonstrate that the less stringent standard of performance they are applying is no less stringent than necessary without evaluating all of the systems of emission reduction in the applicable EG. For example, if the EPA's degree of emission limitation is 95% reduction in emissions and a state applies a less stringent standard of performance that results in 90% reduction, the state may reasonably forgo evaluating additional systems of emission reduction if, based on the information in the EG, it is clear that none is able to achieve comparable reductions. Similarly, a state may not need to consider every system of emission reduction in an applicable EG if it starts by evaluating the system or systems that achieve the greatest emission reductions and applies a standard of performance corresponding to one of those systems.

Third, the EPA anticipates states applying less stringent standards of performance would leverage the information and analyses the Agency has provided in the applicable EG. In promulgating an EG, the EPA is required to provide the elements listed in 40 CFR 60.22a(b), which include ''[a] description of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated,'' and ''[i]nformation on the degree of emission limitation which is achievable with each system, together with information on the costs, nonair quality health environmental [sic] effects, and energy requirements of applying each system to designated facilities,'' as well as ''[s]uch other available information as the Administrator determines may contribute to the formulation of State plans.'' In many cases, the EPA provides extensive technical support documents including feasibility and cost analyses. The Agency also typically discusses the types of nonair quality health and environmental effects and energy requirements that might be expected in conjunction with various systems of emission reduction applicable to the source category. Although designated facilities for which RULOF has been invoked are in fundamentally different circumstances that the average or typical facilities that EPA considers in the context of its own analysis, the information provided in an EG will provide a starting point and, in at least some cases, much of the analytical basis for states' evaluations.

Fourth, in the event the state needs to analyze different systems of emission reduction to determine a less stringent standard of performance, the EPA believes it would be in this position regardless of any requirements the Agency does or does not provide. That is, because CAA section 111(d)(1) requires a standard of performance for each existing source, the EPA does not believe the framework being provided in 40 CFR 60.24a(f) will significantly alter states' workload if and when invoking RULOF. Rather, it is intended to provide clarity for states in developing standards of performance consistent with the statutory requirements. The EPA intends for these requirements to in fact reduce planning burdens overall, as they provide a framework for states to submit approvable standards of performance for sources invoking RULOF, thereby obviating the need for subsequent plan revisions to address any disapproved standards.

As noted above, the EPA requested comment on whether to provide consideration of the five BSER factors as part of a source-specific BSER analysis as a presumptively approvable framework for applying a less stringent standard of performance, as opposed to requirements. The framework the EPA is finalizing in this action differs from the proposed approach under which states would conduct source-specific BSER analyses; the process the EPA is finalizing at 40 CFR 60.24a(f) is premised on determining the appropriate variance from the EPA's degree of emission limitation. The EPA is providing this framework as requirements for states applying a less stringent standard of performance. As explained elsewhere in this section of the preamble, the EPA does not believe it is possible, as a practical matter, to determine a standard of performance that is no less stringent than necessary without evaluating the systems of emission reduction that the EPA determined are adequately demonstrated and engaging with the factors and evaluation metrics that the EPA used to evaluate those systems in the applicable EG. Therefore, the EPA believes that states must use the framework laid out in 40 CFR 60.24a(f) in order for the resulting variance to be consistent with CAA section 111(d). As laid out in the § 60.24a(f)(1), states may also consider additional systems and other factors specific to the facility that were the basis of the fundamental difference identified under 40 CFR 60.24a(e), so long as they justify that any such consideration is consistent with applying a standard of performance that is no less stringent than necessary.

In sum, the EPA is not finalizing its proposed requirement under 40 CFR 60.24a(f)(1) that states that have invoked RULOF for a particular facility determine a source-specific BSER. As a result, it is also not finalizing the provision proposed at 40 CFR 60.24a(f)(2) that would have required states to calculate the emission reductions a source-specific BSER would achieve and apply the standard of performance that reflects this degree of emission reduction. However, consistent with its proposal, the EPA continues to believe it is necessary for the Agency to provide a process for states that have invoked RULOF for a particular facility to follow in applying a less stringent standard of performance. The EPA is therefore promulgating requirements at 40 CFR 60.24a(f) to ensure that states that have invoked RULOF for a particular designated facility apply a standard of performance that is no less stringent than necessary to address the fundamental differences identified under 40 CFR 60.24a(e). These provisions are necessary to ensure consistency with the purpose, text, and context of CAA section 111(d), including an understanding of RULOF as a limited variance from the degree of emission limitation in the applicable EG. The provisions at 40 CFR 60.24a(f)(1) as finalized will require states to determine a less stringent standard of performance that is no less stringent than necessary. In doing so, states must, to the extent necessary, evaluate the systems of emission reduction in that EPA using the factors and evaluation metrics that the EPA considered. States may also consider, as justified, other factors specific to the facility that were the basis for invoking RULOF under 40 CFR 60.24a(e), as well as additional systems of emission reduction. The EPA is finalizing the provision proposed at 40 CFR 60.24a(f)(3), requiring that a less stringent standard of performance pursuant to RULOF be in the form[136] required by the applicable EG, at paragraph (f)(2).

c. Contingency Requirements

The EPA recognizes that a source's operations may change over time in ways that cannot always be anticipated or foreseen by the EPA, state, or designated facility. This is particularly true where the basis of the application of RULOF is a designated facility's operational conditions, such as the source's remaining useful life or restricted capacity. If the designated facility subsequently changes its operating conditions after the state or EPA applies a less stringent standard of performance, the basis for the variance may be abrogated and the standard of performance may no longer be no less stringent than necessary. For example, a state may seek to invoke RULOF for an EGU on the basis that it is running at lower utilization than the EPA considered in determining the degree of emission limitation and intends to do so for the duration of the compliance period required by an EG. Under this scenario, the state may be able to demonstrate that it is not reasonably cost-effective for the designated facility to achieve the degree of emission limitation and the state could set a less stringent standard of performance for this EGU. However, because reduced utilization is not a physical constraint on the designated facility's operations, it is possible that the source's utilization could increase in the future without any other legal constraint.

The EPA proposed to address this potential scenario by adding a contingency requirement to the RULOF provision at 40 CFR 60.24a(h) that would require a state to include in its state plan an instrument making a source's operating condition, such as remaining useful life or restricted capacity, enforceable whenever the state seeks to rely on that operating condition as the basis for a less stringent standard. This requirement would not extend to instances where a state applies a less stringent standard on the basis of an unalterable condition that is not within the designated source's control, such as technical infeasibility, space limitations, water access, or geologic sequestration access. Rather, this requirement addresses operating conditions such as operation times, operational frequency, process temperature and/or pressure, fuel parameters, and other conditions that are subject to the discretion and control of the designated facility.

Many commenters on this subject supported the EPA's proposed approach to operating conditions that are within a designated facility's control. They noted that, in the absence of an enforceable requirement, a designated facility could change its operations with the result being foregone emission reductions and undermining of the level of stringency in the EG. One commenter stated that the EPA should not permit a source that has legally committed to a retirement date as a condition of invoking RULOF to receive a less-stringent standard to postpone that date because, even if it committed to meet the emission limitation in the EG from that point forward, it could not make up for its excess emissions before that time. Other commenters opposed the EPA's proposed requirement and asserted that the EPA had cited no legal authority or record basis for a need to require states to make operational conditions that are the basis of less stringent standards into enforceable requirements in state plans. One commenter noted that states should have latitude in their regulatory and permit processes to determine what additional restrictions or contingencies are necessary to ensure that the less stringent standard remains appropriate over time.

The EPA continues to believe the requirement proposed at 40 CFR 60.24a(h) is a necessary and reasonable safeguard to ensure that designated facilities' standards of performance are consistent with the level of stringency Congress required. Where are particular facility's operating conditions are the basis for a variance from the EPA's degree of emission limitation, that variance is warranted only so long as the operating condition remains a fundamental difference between that facility's circumstances and the information the EPA considered in the applicable EG. Therefore, in order for a state plan to include satisfactory standards of performance as well as measures for the implementation and enforcement of those standards pursuant to CAA section 111(d)(1), the contingency must be an enforceable requirement in that plan; upon EPA approval of the plan the contingency becomes a federally enforceable requirement (in addition to being enforceable through the state-law instrument that was included in the plan). Inclusion in a state permit, rule, or other instrument alone is not sufficient to satisfy CAA section 111(d)(1). A state-only instrument can additionally be changed outside the state plan revision process, which could result in the lifting of the operational condition without a corresponding adjustment to the designated facility's less stringent standard of performance.

The EPA notes that it has a practice of requiring operational conditions that

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[136] "Form" of the less stringent standard of performance refers to a numerical emissions standard versus a work practice standard, the units in which a standard is expressed, or both.

are the basis of less stringent emission limitations to be included in state plans or state implementation plans under CAA section 111 or 110, respectively, including in the Affordable Clean Energy Rule[137] and under the CAA's regional haze program.[138]

States may revise their state plans to allow a designated facility that has committed to retiring as the basis for invoking RULOF to postpone its retirement date. There could be many reasons a designated facility that previously agreed to a federally enforceable commitment to cease operations by a certain date might need to extend that date. The EPA is unable to assess, in the context of these general implementing regulations, an appropriate approach for all possible circumstances to ensure that the level of stringency of the EG is not undermined. The EPA anticipates addressing this consideration in individual EGs.

As previously discussed, the state plan submission must also include measures for the implementation and enforcement of a standard that accounts for RULOF. For standards that are based on operating conditions that a facility has discretion over and can control, the operating condition and any other measure that provides for the implementation and enforcement of the less stringent standard must be included in the plan submission and as a component of the standard of performance. For example, if a state applies a less stringent standard for a designated facility on the basis of a lower capacity factor, the plan submission must include an enforceable requirement for the source to operate at or below that capacity factor, and include monitoring, reporting, and recordkeeping requirements that will allow the state, the EPA, and the public to ensure that the source is in fact operating at that lower capacity. A specific EG may detail supplemental or different requirements on implementing the proposed general requirement that a state plan submission include both the operating condition that is the basis for a less stringent standard, and measures to provide for the implementation and enforcement of such standard.

The EPA notes there may be circumstances under which a designated facility's operating conditions change permanently so that there may be a potential violation of the contingency requirements approved as federally enforceable components of the state plan. For example, a designated facility that was previously running at lower capacity now plans to run at a higher capacity full time, which conflicts with the federally enforceable state plan requirement that the facility operate at the lower capacity. To address this concern, a state may submit a plan revision to reflect the change in operating conditions. Such a plan revision must include a new standard of performance that accounts for the change in operating conditions. The plan revision would need to include a standard of performance that reflects the degree of emision limitation required by the EG and meet all applicable requirements, or if a less stringent standard is still warranted for other reasons, the plan revision would need to meet all of the applicable requirements for considering RULOF. The new standard of performance would only become effective upon the EPA's determination that the plan revision is satisfactory.

The EPA is finalizing as proposed the requirement that, where a plan applies a less stringent standard of performance on the basis of an operating condition within the designated facility's control, such as remaining useful life or restricted capacity, the plan must also include such operation condition or conditions as an enforceable requirement (this requirement was proposed at 40 CFR 60.24a(h) and is being finalized at 40 CFR 60.24a(g)). The plan must also include requirements to provide for the implementation and enforcement of the operating condition, such as monitoring, reporting, and recordkeeping requirements.

d. Requirements Specific to Remaining Useful Life

CAA section 111(d) explicitly requires that the EPA permit states to consider remaining useful life in applying a standard of performance. While the EPA may consider the age of designated facilities within a source category as a general matter in determining the BSER, it is a factor that can have considerable variability from facility to facility. The annualized costs can change considerably based on the applied technology at any particular designated facility given the amortization period. When the EPA determines a BSER, it considers cost and, in many instances, specifically considers annualized costs associated with payment of the technology associated with the BSER. The shorter that payback period is (*i.e.,* shorter remaining useful life), the less cost-effective that BSER may become. The current RULOF provision in subpart Ba generally allows for a state to account for remaining useful life to set a less stringent standard. However, the provision does not provide guidance or parameters on when and how a state may do so.

Consistent with the principles described previously in section III.E., the EPA proposed requirements for when a state seeks to apply a less stringent standard on grounds that a designated facility will retire in the near future. Specifically, the EPA proposed that the Agency would be required to identify in an EG the outermost retirement date for designated facilities that could qualify for consideration of remaining useful life, or a methodology and considerations for states to use in determining such an outermost date. The proposed regulations would have also allowed states to apply a routine maintenance standard of performance to designated facilities with ''imminent'' retirement dates and additionally provided that the EPA may define the timeframe for imminent retirements in an EG. Finally, consistent with the proposed provisions regarding contingency requirements, the EPA proposed that any state plan that applies a standard of performance that is based on a particular designated facility's remaining useful life must include the retirement date as an enforceable commitment and provide measures for its implementation and enforcement.

Several commenters supported the EPA's proposal to identify in an EG an outermost and imminent retirement date to guide states' consideration of remaining useful life in setting less stringent standards. Some supportive commenters also urged the EPA to prescribe further requirements for designated facilities that rely on a shorter remaining useful life, including prohibiting them from extending their retirement dates and defining an imminent retirement as one that occurs within two years of state plan submission. Other commenters opposed the EPA's proposed requirements around the consideration of remaining useful life. Some argued that the requirements would foreclose states from considering remaining useful life when a designated facility's retirement date falls outside the prescribed range and that, although states must reasonably exercise their discretion, the

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[137] 84 FR 32520, 32558 (July 8, 2019). The EPA has proposed to repeal the ACE Rule on other grounds. See 88 FR 33240 (May 23, 2023).

[138] See, *e.g.,* 76 FR 12651, 12660–63 (March 8, 2011) (best available retrofit technology requirements for Oregon source based on enforceable retirement that were to be made federally enforceable in state implementation plan); Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 34, EPA–457/B–19–003, August 2019 (to the extent a state relies on an enforceable shutdown date for a reasonable progress determination, that measure would need to be included in the SIP and/or be federally enforceable).

CAA puts no limits on their consideration of this factor. Adverse commenters also noted that the remaining useful life consideration is very source-specific and that there may be relevant factors that the EPA would not necessarily take into account when determining the outermost and imminent dates in an EG.

After consideration of the comments received, the EPA has decided not to finalize the provisions proposed at 40 CFR 60.24a(i) regarding remaining useful life. As a general matter, the proposed requirement for the EPA to identify an outermost and imminent retirement date for the consideration of remaining useful life was intended to assist states in developing their state plans and to provide transparency and consistency in states' application of, and the EPA's review of, standards of performance based on this factor. As explained in the preamble to the proposed rule, a designated facility's remaining useful life generally impacts a cost analysis by changing the amortization period, or the period of time over which a facility pays the capital costs for a system of emission reduction. The shorter the period, the higher the annualized costs. The EPA generally assumes a certain amortization period in its BSER determination based on, *e.g.,* the lifespan of the system under consideration and the characteristics of facilities within the source category. A designated facility that has a shorter remaining useful life than the amortization period the EPA assumed in its BSER determination will likely find that achieving the degree of emission based on application of the BSER has higher annualized costs; the larger the difference between a particular facility's remaining useful life and the EPA's assumed amortization period, the larger the difference in annualized costs. However, as a factual matter, there is a point at which a designated facility's remaining useful life is long enough so that the difference in annualized costs for that facility and the costs the EPA considered reasonable in the applicable EG are not fundamentally different. At this point, it would be unreasonable for a state to use remaining useful life as the basis for a less-stringent standard for that facility because it could achieve the EPA's degree of emission limitation at a reasonable cost.

Similarly, an imminent retirement date could serve to streamline states' planning for sources with remaining useful lives that are so short that, as a factual matter, no available system of emission reduction could have reasonable costs. What constitutes a reasonable cost in the context of a specific EG could depend on, *inter alia,* the source category, the emission reductions available, and the designated pollutant.

However, the EPA agrees with commenters that states' consideration of remaining useful life and what constitutes reasonable consideration of this factor will necessarily depend on the source category, the variability of the individual designated facilities within the source category, and the structure of the applicable EG. In some instances, the nature of the designated facilities and structure of the EG may render a designated facility's remaining useful life of little relevance. For example, where a BSER is based on operational changes or activities that entail little to no capital cost, the remaining useful life of a designated facility should not change the reasonableness of the system and there would be no need for the EPA to prescribe imminent and outermost retirement dates in an EG. Alternatively, designated facilities within the source category may, by virtue of how an industry developed, fall into discrete age classes based on their remaining useful lives such that the EPA considers this characteristic in creating subcategories and determining appropriate BSERs for each subcategory. In this case, too, there might be little utility in the EPA defining imminent and outermost dates for consideration of remaining useful life in an EG.

The EPA is therefore choosing not to finalize the provisions proposed at 40 CFR 60.24a(i), although it may be appropriate to include outermost and imminent retirement dates for the consideration of remaining useful life in individual EGs. The proposed provisions included a requirement that any plan that applies a less-stringent standard based on remaining useful life must include the retirement date for the designated facility as an enforceable commitment, including any measures that provide for the implementation and enforcement of such a commitment. The EPA notes that although it is not finalizing the proposed 40 CFR 60.24a(i)(3), as discussed in section III.E.3.c. of this preamble plans that include less-stringent standards based on remaining useful life will still be required to include the relevant designated facilities' retirement dates as enforceable commitments and include any measures necessary to provide for the implementation and enforcement of those commitments pursuant to the requirement being finalized at 40 CFR 60.24a(g).

The EPA also reiterates that the obligation to include a standard of performance in a state plan applies to any designated facility that meets the applicability requirements of an EG as of that EG's compliance date. That is, a state plan must include a standard of performance for a designated facility that is retiring after the compliance date, even if the facility has an enforceable commitment to retire imminently following that date. In the case of an imminently retiring designated facility, it may be reasonable for a state to apply a standard reflecting that facility's business as usual; the EPA will address this and other potential considerations, including how such a standard would be calculated, in individual EGs.

e. Reasoned Decision Making and the EPA's Review of State Plans Invoking RULOF

As discussed previously in section III.E. of this preamble, under CAA section 111(d)(2), the EPA has the obligation to determine whether a state plan submission is ''satisfactory.'' This obligation extends to all aspects of a state plan, including the application of a less stringent standard of performance that accounts for RULOF. States carry the primary responsibility to develop plans that meet the requirements of CAA section 111(d) and therefore have the obligation to justify any consideration of RULOF in applying standards less stringent than the degree of emission limitation provided by the EG. That states must provide a reasoned basis including, where applicable, technical analyses and other documentation to support the decisions they make in their plans is fundamental to the structure of CAA section 111(d).[139] As explained in section III.E.3.a. of this preamble, consistent with the statutory framework of CAA section 111(d), state plans must ensure that designated facilities achieve the degree of emission limitation achievable through application of the BSER as determined by the EPA unless doing so would be unreasonable for a particular facility. The fundamental tenet has been reflected in the EPA's regulations since 1975.[140] Thus, a ''satisfactory'' plan is one that, *inter alia,* applies less-stringent standards only where the state has demonstrated that achieving the EPA's degree of emission limitation would be unreasonable pursuant to 40 CFR 60.24a(e). A demonstration that a particular designated facility cannot

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[139] See, *e.g.,* 84 FR 32558 (ACE Rule explained that state plans must adequately document and demonstrate the process and underlying data used to establish standards of performance so that EPA can adequately and appropriately review the plan to determine whether it is satisfactory).

[140] See 40 CFR 60.24(c), 60.24a(c).

reasonably achieve the degree of emission limitation determined by the EPA will, in most cases, necessarily be supported by technical analysis that assesses a particular designated facility and compares its circumstances to those the EPA considered in its EG.

While it is within states' discretion to apply a less stringent standard of performance where the state has identified fundamental differences for a particular facility (or class of facilities), the state must support its decision making and demonstrate that it results in a standard of performance that is no less stringent than necessary to address the fundamental differences and that meet the applicable requirements. When a state invokes RULOF and applies a less-stringent standard, it must demonstrate that the standard is no less stringent than necessary to address the fundamental difference identified by the state. Absent such a demonstration, the EPA cannot ascertain that a less-stringent standard meets the requirements of CAA section 111; that is, it cannot determine that a less-stringent standard is ''satisfactory.''

The requirements proposed at 40 CFR 60.24a(j) were intended to explicitly clarify states' responsibilities when invoking RULOF and to assist them in developing standards in a manner that enables the Agency to determine whether such standards are ''satisfactory.'' The proposed requirements provided that states would carry the burden of making any demonstrations in support of less-stringent standards pursuant to the RULOF provisions. States would carry the primary responsibility to develop plans that meet the requirements of CAA section 111(d) and therefore have the obligation to justify any accounting for RULOF in support of standards less stringent than those provided by the EG. While the EPA has discretion to supplement a state's demonstration, the Agency may also find that a state plan's failure to include a sufficient RULOF demonstration is a basis for concluding the plan is not ''satisfactory'' and therefore disapprove the plan. The EPA further proposed that for the required demonstrations, states must use information that is applicable to and appropriate for the specific designated facility, and must show how information is applicable and appropriate. As RULOF is a source-specific determination, it is appropriate to require that the information used to justify a less stringent standard for a particular designated facility be applicable to and appropriate for that source. Finally, the EPA proposed to require that the information used for states' demonstrations under the new RULOF provisions must come from reliable and adequately documented sources, such as EPA sources and publications, permits, environmental consultants, control technology vendors, and inspection reports.

Comments received on the proposed requirements regarding states' burden of demonstration and the use of site-specific information were generally supportive while also requesting further clarification of and flexibility in the types of information that the EPA would consider acceptable. One commenter suggested that the EPA allow states to use historical data even if not published or documented by third parties, as this constitutes site-specific information, while another suggested allowing verified industry information, even if it is not site-specific.

Despite the generally supportive commenters received, the EPA is not finalizing the requirements proposed at 40 CFR 60.24a(j). While the EPA continues to find that states carry the burden of making any demonstrations in support of less-stringent standards pursuant to RULOF in developing their plans, we have determined that it is not necessary to promulgate this expectation as a standalone regulatory requirement. States always bear the responsibility of reasonably documenting and justifying the standards of performance in their plans.[141] If the EPA cannot ascertain, based on the information and analysis included in a state plan submission, whether a standard of performance meets the statutory requirements, it cannot find that standard satisfactory. Additionally, it is *de facto* necessary to use information that is applicable to and appropriate for the designated facility when analyzing systems of emission reduction for that particular facility. For example, for a designated facility invoking RULOF based on its unique design features, the state plan must provide information corroborating the uniqueness of those features and analysis demonstrating how they result in the facility being unable to reasonably achieve the degree of emission limitation determined by the EPA. It would not be reasonable in this instance for a state to use generic industry data, whether verified or not, as the basis of demonstrations pursuant to 40 CFR 60.24a(e) and (f).

While the proposed requirements would have simply codified generally applicable tenets of reasoned decision making, the EPA recognizes that the specific types and provenances of information needed to justify a less-stringent standard can vary significantly between not only source categories, but between individual designated facilities within a source category. As a result, the proposed provisions had the potential to be both over- and underinclusive. While we are not finalizing these provisions as generally applicable requirements for state plans, they and the accompanying discussion in the notice of proposed rulemaking[142] remain important guidance for plan development. The EPA may also choose to promulgate requirements for RULOF demonstrations in individual EGs.

f. Consideration of Impacted Communities

While the consideration of RULOF can be warranted to apply a less stringent standard of performance to a particular facility, such standards have the potential to result in disparate health and environmental impacts to communities most affected by and vulnerable to those impacts from the designated facilities being addressed by the state plan. These communities could be put in the position of bearing the brunt of the greater health or environmental impacts resulting from that source implementing less stringent emission controls than would otherwise have been required pursuant to the EG. The EPA considers that a lack of attention to such potential outcomes would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally. Because of CAA section 111(d)(2)'s requirement that the EPA determine whether a state plan is ''satisfactory'' applies to such plan's consideration of RULOF in applying a standard of performance to a particular facility, the EPA must determine whether a plan's consideration of RULOF is consistent with CAA section 111(d)'s overall health and welfare objectives.

In order to address the potential exacerbation of health and environmental impacts to these communities as a result of applying a less stringent standard, the EPA proposed to require states to consider such impacts when applying the RULOF provision to establish those standards. Under the proposed provisions at 40 CFR 60.24a(k), to the extent a designated facility would qualify for a less stringent standard through

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[141] Where a state has relied on information or analyses the EPA provided in an applicable EG as part of its source specific BSER determination, a state would explain why such reliance is reasonable and cite or otherwise incorporate that information or analyses in its state plan submission.

[142] See 87 FR 79176, 79202–03 (Dec. 23, 2022).

consideration of RULOF, the state, in calculating such standard, would have been required to demonstrate consideration of the potential health and environmental impacts and potential benefits of control to communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions. These communities will be identified by the state as pertinent stakeholders under the finalized meaningful engagement completeness requirements described in section III.C. of this preamble.

The notice of proposed rulemaking further explained that state plan submissions seeking to invoke RULOF for a source would be required to identify where and how a less stringent standard impacts these communities. In evaluating a RULOF option for a facility, states should describe the health and environmental impacts anticipated from the application of RULOF for such communities, along with any feedback the state received during meaningful engagement regarding its draft state plan submission, including on any standards of performance that consider RULOF. Additionally, to the extent there is a range of options for reasonably controlling a source based on RULOF, the EPA proposed that in determining the appropriate standard of performance, states should consider the health and environmental impacts to the communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions and provide in the state plan submission a summary of the results that depicts potential impacts for those communities for that range of reasonable control options.

The EPA received a wide range of comments on the proposed requirements for state plans to consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from a designated facility that is invoking RULOF. Several commenters supported the proposal and agreed that, given that the purpose of regulating stationary source pollution under CAA section 111 is to address emissions that endanger public health and welfare, requiring states that are applying less-stringent standards to take into account how air pollution above the level reflected by application of the BSER may impact the health and welfare of local communities furthers the statutory design. Other commenters agreed that the EPA has authority to require states to consider the impacts of less-stringent standards of performance on vulnerable communities but expressed concern that the lack of specificity of and guidance for implementing the proposed requirements would cause uncertainty among state regulators and impacted communities and lead to unequal application across states. Similarly, one commenter noted the differences between community impacts when considering localized pollutants versus regional or global pollutants and that impacts of the latter are more diffuse and difficult to assess. Some commenters, however, disagreed that the EPA has authority to require states to consider potential health and environmental impacts of less-stringent standards on vulnerable communities. These commenters generally asserted that the state-focused language of the RULOF provision in CAA section 111(d)(1) does not mandate an analysis of vulnerable communities and does not give the EPA power to force states to consider ''other factors'' that it deems relevant.

The EPA is not finalizing the proposed provisions at 40 CFR 60.24a(k) as requirements under the general implementing regulations. We agree with commenters that additional specificity and guidance with regard to how states should consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from a designated facility invoking RULOF would be key to ensuring meaningful implementation of this provision. However, given the diversity of source categories, designated facilities, and designated pollutants that are regulated and could be regulated in CAA section 111(d), as well as the wide range of potential impacts on vulnerable communities that may result from less-stringent standards of performance under any given EG,[143] the EPA does not believe it is either feasible or appropriate to prescribe a universally applicable approach or standard for approvability for this consideration. Instead, to protect all communities, including the most vulnerable ones, the EPA is finalizing a provision that will ensure that any less stringent standards of performance applied by states are no less stringent than necessary. Moreover, because consideration of health and environmental impacts is inherent in consideration of both the nonair quality health and environmental impacts and amount of emission reduction factors the EPA considers under CAA section 111(a)(1), when a state considers the systems of emission reduction identified in the applicable emission guideline using the factors and evaluation metrics the EPA considered in assessing those systems pursuant to RULOF, the state will necessarily consider the potential impacts and benefits of control to communities affected by a designated facility that is receiving a less-stringent standard of performance.

Thus, while the EPA is not promulgating a regulatory requirement in subpart Ba for states to consider the impacts of applying a less-stringent standard of performance on the communities most affected by and vulnerable to emissions from a designated facility invoking RULOF, the EPA anticipates that states will consider these impacts. To this end, states may look to the EPA's emission guideline and its consideration of nonair quality health and environmental impacts and the amount of emission reductions available in determining the degree of emission limitation for guidance on considering the health and environmental impacts on communities affected by a designated facility for which RULOF has been invoked. Additionally, the procedural requirements under subpart Ba for meaningful engagement with pertinent stakeholders on state plan development that the EPA is finalizing will play an important role in RULOF. Meaningful engagement, which the EPA is defining as ''timely engagement with pertinent stakeholder representation in the plan development or plan revision process,''[144] and providing that ''[s]uch engagement should not be disproportionate in favor of certain stakeholders and should be informed by available best practices,'' should address, *inter alia,* the application of any less-stringent standards of performance pursuant to RULOF. Thus, the EPA intends for communities most affected by and vulnerable to the health and environmental impacts of pollution from a designated facility invoking RULOF to have an opportunity to participate in the process of determining how that facility is addressed in the relevant state plan. The EPA may also consider whether to promulgate requirements pertaining to consideration of impacts on vulnerable communities as part of an individual EG in the future, at which point it would

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[143] In the notice of proposed rulemaking, the EPA ''recognize[d] that the consideration of communities in the standard setting process, such as what constitutes a benefit to a vulnerable community and what is a reasonable level of control, is highly dependent on the designated pollutant and source category subject to an EG.'' 87 FR 79203.

[144] The EPA is also finalizing the proposed definition of ''pertinent stakeholders'' to include those who are most affected by and vulnerable to the health or environmental impacts of pollution from the designated facilities addressed by the plan or plan revision.

provide guidance on how to do so specific to the designated facilities and designated pollutant at issue.

g. Authority To Apply More Stringent Standards as Part of the State Plan

The EPA, in the notice of proposed rulemaking, addressed two different sources of authority that would allow the Agency to approve state plans that include standards of performance that are more stringent than the degree of emission limitation determined by the EPA in the applicable EG. First, the EPA explained that allowing states to apply a more stringent standard of performance as part of their CAA section 111(d) plans is consistent with CAA section 116, which generally authorizes states to include more stringent standards of performance or requirements regarding control or abatement of air pollution in their plans. Second, the EPA proposed to interpretation the RULOF provision in CAA section 111(d)(1), and specifically the ''other factors'' consideration, as allowing states to adopt more stringent standards of performance.[145] As explained below, the EPA is not finalizing its proposed interpretation that states can use the RULOF provision in CAA section 111(d)(1) to adopt, and have the EPA approve, more stringent standards of performance in their state plans because, inter alia, states already have the authority and ability to do so under CAA section 116.

As explained in the notice of proposed rulemaking, the anti-preemption requirements of CAA section 116 provide that nothing in the statute shall preclude or deny the right of states to adopt or enforce ''any standard or limitation respecting emissions of air pollutants.'' While CAA section 116 clearly extends to a state adopting or enforcing a standard of performance more stringent than required under CAA section 111(d), the subpart Ba implementing regulations did not explicitly speak to whether the EPA can approve a state plan that includes such standard of performance. However, the EPA proposed to find that CAA section 116, as interpreted through the Supreme Court in *Union Electric Co.* v. *EPA,*[146] requires the EPA to approve a state plan that includes more stringent standards of performance under CAA section 111(d). The EPA therefore proposed to modify the existing 40 CFR 60.24a(f),[147] clarifying that to the extent a state chooses to submit a plan that includes standards of performance that are more stringent or compliance schedules that are more rapid than the requirements of an EG, states have the authority to do so under this provision and CAA section 116. Further, the EPA proposed to clarify that it has the obligation, and therefore the authority, to review and approve such plans and render the more stringent requirements federally enforceable if all applicable requirements are met.

The EPA is finalizing the proposed changes to the provision currently at 40 CFR 60.24a(f) which, as renumbered pursuant to this final rule, is now 40 CFR 60.24a(i). The Agency acknowledges that it previously took the position in the ACE Rule that *Union Electric* does not control the question of whether CAA section 111(d) state plans may be more stringent than Federal requirements. The EPA took this position in the ACE Rule on the basis that *Union Electric* on its face applies only to CAA section 110, and that it is ''potentially salient'' that CAA section 111(d) is predicated on specific technologies whereas CAA section 110 gives states broad latitude in the measures used for attaining the NAAQS.[148] The EPA no longer takes this position. Upon further evaluation, the EPA finds that, because of the structural similarities between CAA sections 110 and 111(d), CAA section 116 as interpreted by *Union Electric* requires the EPA to approve CAA section 111(d) state plans that are more stringent than required by the EG.

The Court in *Union Electric* rejected a construction of CAA sections 110 and 116 that measures more stringent than those required to attain the NAAQS cannot be approved into a federally enforceable SIP but can be adopted and enforced only as a matter of state law. The Court found that such an interpretation of CAA section 116 ''would not only require the Administrator to expend considerable time and energy determining whether a state plan was precisely tailored to meet the Federal standards but would simultaneously require States desiring stricter standards to enact and enforce two sets of emission standards, one federally approved plan and one stricter state plan.'' 427 U.S. at 263–64. The Court concluded there was no basis ''for visiting such wasteful burdens upon the States and the Administrator.'' *Id.* CAA sections 111(d) and 110 are structurally similar in that both require the EPA to establish targets to meet the objectives of the respective sections (*i.e.,* the degree of emission limitation set by an EG under CAA section 111(d), and attainment and maintenance of the NAAQS under CAA section 110), and states must adopt and submit to the EPA plans which include requirements to meet these targets. Specifically, the EPA establishes a presumptive standard of performance corresponding to the degree of emission limitation it has determined in an EG, and state plans under CAA section 111(d) must establish standards of performance that generally reflect this degree of emission limitation. Because CAA section 116 applies to ''any standard or limitation,'' this provision clearly applies to standards of performance adopted under CAA section 111(d). Therefore, the Court's rationale in *Union Electric* as it pertains to the application of CAA section 116 in the context of the cooperative federalism structure of CAA section 110 also applies to CAA section 111(d). That is, the assessment of CAA section 116 in the context of requirements that states develop and submit to the EPA for evaluation against nationally applicable standards or criteria applies equally to CAA sections 110 and 111(d). On that basis, the EPA is finding that the Court's holding applies and controls the outcome here, as well. Requiring states to enact and enforce two sets of standards of performance, one that is exactly equal to the EPA's presumptive standard of performance that is federally approved as part of the CAA section 111(d) plan and one that is stricter and is only adopted and enforced as a matter state requirements, runs directly afoul of *Union Electric'*s holding that there is no basis for interpreting CAA section 116 in such manner.

Moreover, there is nothing in CAA section 111(d) that precludes states from adopting, and EPA from approving, more stringent standards of performance.[149] In fact, permitting

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[145] 87 FR 79204–06.

[146] 427 U.S. 246, 263–64 (1976).

[147] The existing provision at 40 CFR 60.24a(f) provides that ''[n]othing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing,'' (1) standards of performance more stringent than an EG, or (2) compliance schedules requiring final compliance at earlier times than specified in an EG. In the proposed rulemaking, the EPA added several proposed provisions to 40 CFR 60.24a, which resulted in § 60.24a(f), in addition to being amended, being renumbered as § 60.24a(n). However, the EPA is not finalizing all the new provisions it proposed; as a result, erstwhile § 60.24a(f) is now being finalized, with amendments, at § 60.24a(i).

[148] 84 FR 32559–61.

[149] In the 1975 CAA section 111(d) implementing regulations the Agency explained that EPA's emission guidelines will reflect its judgment of the degree of control that can be attained by various classes of existing source without unreasonable costs. Particular sources within a class may be able to achieve greater control without unreasonable costs. Moreover, States that believe additional

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states to adopt more stringent standards of performance and include such standards in their state plans is entirely consistent with the purpose and structure of CAA section 111(d). States bear the obligation pursuant to CAA section 111(d)(1) to establish standards of performance. Nothing in CAA section 111(d) suggests that Congress intended to preclude states from determining that it is appropriate to regulate certain sources within their jurisdiction more strictly than otherwise required by Federal requirements. For the EPA to do so would be arbitrary and capricious in light of the overarching purpose of CAA section 111(d), which is to require emission reductions from existing sources for certain pollutants that endanger public health or welfare. It is inconsistent with the purpose of CAA section 111(d) and the role it confers upon states for the EPA to constrain them from further reducing emissions that harm their citizens, and the EPA does not see a reasonable basis for doing so.

The EPA also included a second rationale for permitting more stringent standards of performance in the notice of proposed rulemaking. The Agency explained that CAA section 111(d)(1) provides that states are permitted to consider remaining useful life and other factors ''in applying a standard of performance to any particular source under a plan,'' but does not specify that the source-specific standard must be a *less stringent* standard of performance. Aside from the explicit reference to remaining useful life, the statute is silent as to what the ''other factors'' are that states may consider in applying a standard of performance and whether such factors can be used only to weaken the stringency of a standard of performance for a particular designated facility. Therefore, in addition to proposing that states may include, and the EPA must approve, more stringent standards of performance in state plans pursuant to CAA sections 111(d) and 116, the EPA also proposed to interpret CAA section 111(d)(1) as allowing states to consider ''other factors'' in exercising their discretion to apply a more stringent standard to a particular source. The Agency acknowledged that it had previously, in promulgating subpart Ba in 2019, taken the position that the statutory RULOF provision authorizes only standards of performance that are less stringent than the presumptive level of stringency required by a particular EG,[150] and explained why it was proposing to change course. To codify its revised interpretation of the RULOF provision, the EPA proposed explicit regulatory text that would have allowed states to use RULOF, and specifically, ''other factors,'' to apply a more stringent standard of performance. The new provision at 40 CFR 60.24a(m) would have also required that state plans include an adequate demonstration that the standard of performance is more stringent than required by an application EG and meet all other applicable requirements.

The EPA received comments both in support of and opposed to its proposed interpretation that states may apply more stringent standards of performance and that EPA has an obligation to approve such standards in state plans. Several commenters stated the Agency has appropriately interpreted CAA section 116 and 111(d), as well as *Union Electric Co.* v. *EPA,* as allowing states to submit, and the EPA to approve, more stringent standards. One commenter also agreed that the statutory phrase ''remaining useful life and other factors'' does not foreclose a state plan from applying a more stringent standard of performance to a particular source; while ''remaining useful life'' implies a less stringent standard, ''other factors'' does not. Another commenter asserted that the EPA need not rely on ''other factors'' to permit states to apply more stringent standards because states already have the ability to do so in light of the Supreme Court's ruling in *Union Electric.* Commenters that disagreed with the EPA's proposed interpretation generally recognized that states can adopt more stringent rules than those required by the EPA but asserted that the CAA does not authorize the EPA to approve them into state plans and thus make them federally enforceable. One commenter argued that the EPA's BSER determination defines the extent of both EPA and state authority under CAA section 111 and that the RULOF provision does not authorize states to select a different, more stringent BSER under the guise of RULOF. Another commenter stated that the EPA's position that RULOF is a variance provision for sources that cannot meet the BSER due to limited remaining useful life or other factors is in tension with its interpretation that the same provision provides a broad grant of authority for states to impose more stringent standards on sources. The same commenter pointed out the difference in proposed requirements for states invoking RULOF to apply a less stringent standard and those for applying a more stringent standard.

The EPA agrees with commenters that it need not rely on ''other factors'' for authority to permit states to submit, and the EPA to approve, more stringent standards of performance in state plans. As explained above, CAA sections 116 and 111(d), and the Court's interpretation in *Union Electric* of section 116 as it relates to CAA section 110's analogous statutory framework, provide a sufficient basis this position. Moreover, upon further consideration of the history of the RULOF provision and the EPA's interpretation of that provision as a variance for states to use when a source cannot reasonably achieve the degree of emission limitation determined by the EPA, the Agency is not finalizing its proposed interpretation that the RULOF provision allows states to adopt more stringent standards of performance in their plans. The EPA is therefore not finalizing the provision it proposed at 40 CFR 60.24a(m) that would have explicitly allowed a state to ''account for other factors in applying a standard of performance that is more stringent than required by an applicable emission guideline, or the proposed provision that ''[t]he plan must include an adequate demonstration that the standard of performance is more stringent than required by an applicable emission guideline, and must meet all other applicable requirements, such as those that provide for the implementation and enforceable of the more stringent standard of performance.'' As a general matter, states already bear the burden of demonstrating that their standards of performance are no less stringent than the corresponding EG. See 40 CFR 60.24a(c).

The EPA disagrees with comments suggesting that the EPA's BSER determination is the ceiling—that the EPA is constrained from approving more stringent standards of performance into state plans. As explained above, there is no support for this position in the statutory language or structure of CAA section 111(d). It is also inconsistent with CAA section 116 and would run counter to the purpose of section 111—reducing emissions of dangerous air pollutants from designated facilities.

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control is necessary or desirable will be free under section 116 of the Act to require more expensive controls, which might have the effect of closing otherwise marginal facilities, or to ban particular categories of sources outright. 40 FR 53343. Congress did nothing to disturb the understanding that states can use CAA section 116 to adopt more stringent standards of performance when it enacted the 1977 CAA Amendments shortly thereafter.

[150] See EPA's Responses to Public Comments on the EPA's Proposed Revisions to Emission Guideline Implementing Regulations at 56 (Docket ID No. EPA–HQ–OAR–2017–0355–26740) (July 8, 2019).

The EPA anticipates that, in many cases, more stringent standards of performance would entail marginal differences in stringency between the degree of emission limitation in the applicable EG and the state plan requirement. For example, the EPA may determine that, for the source category in general, a control technology can reasonably achieve an 80% reduction in emissions, while a state finds that at a particular designated facility, that same control technology can reasonably achieve a 90% reduction. Or a state may decide that a particular designated facility can install a control technology that has already been demonstrated to reasonably achieve greater emission reductions than the BSER the EPA determined for the source category generally. The EPA also notes that approving more stringent standards of performance in state plans is not a new practice under subpart Ba; for example, in 2020 the EPA approved more stringent standards of performance that California submitted as part of its CAA section 111(d) state plan to implement the emission guidelines for landfill gas emissions from municipal solid waste landfills. These more stringent standards of performance were incorporated into the Code of Federal Regulations and thus became federally enforceable.[151]

In summary, the EPA is finalizing, at 40 CFR 60.24a(i), the proposed revisions to the existing provision (currently at 40 CFR 60.24a(f)) stating that nothing in subpart Ba shall be construed to preclude any state from adopting or enforcing, as part of a state plan, (1) standards of performance more stringent that the applicable EG, or (2) compliance schedules requiring final compliance at earlier times than specified in the applicable EG. The EPA is not finalizing the regulatory text provision proposed at 40 CFR 60.24a(m) stating that a state may account for other factors in applying a more stringent standard of performance.

F. Provision for Electronic Submission of State Plans

The EPA proposed to revise subpart Ba to require electronic submission of state plans instead of paper copies.[152] As explained in the notice of proposed rulemaking, the regulations promulgated in 2019 require state plan submissions to be made in accordance with 40 CFR 60.4. Pursuant to 40 CFR 60.4(a), all requests, reports, applications, submittals, and other communications to the Administrator pursuant to 40 CFR part 60 shall be submitted in duplicate to the appropriate regional office of the EPA. The provision in 40 CFR 60.4(a) then proceeds to list the corresponding addresses for each regional office. The EPA proposed that, rather than requiring paper copies of state plan submissions to be sent to the appropriate regional office, states would submit their state plans electronically via the use of its State Planning Electronic Collaboration System (SPeCS).

As previously described, CAA section 111(d) requires the EPA to promulgate a ‘‘procedure’’ similar to that of CAA section 110 under which states submit plans. The statute does not prescribe a specific platform for plan submissions, and the EPA reasonably interprets the procedure it must promulgate under the statute as allowing it to require electronic submission. Requiring electronic submission is reasonable for the following reasons. Providing for electronic submittal of CAA section 111(d) state plans in subpart Ba in place of paper submittals aligns with current trends in electronic data management and as implemented in the individual EGs will result in less burden on the states. It is the EPA’s experience that the electronic submittal of information increases the ease and efficiency of data submittal and data accessibility. The EPA’s experience with the electronic submittal process for SIPs under CAA section 110 has been successful as all the states are now using the SPeCS, which is a user-friendly, web-based system that enables state air agencies to officially submit SIPs and associated information electronically for review and approval to meet their CAA obligations related to attaining and maintaining the NAAQS. SPeCS for SIPs is the EPA’s preferred method for receiving such SIPs submissions. The EPA has worked extensively with state air agency representatives and partnered with E-Enterprise for the Environment and the Environmental Council of the States to develop this integrated electronic submission, review, and tracking system for SIPs. SPeCS can be accessed by the states through the EPA’s Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The CDX is the Agency’s electronic reporting site and performs functions for receiving acceptable data in various formats. The CDX registration site supports the requirements and procedures set forth under the EPA’s Cross-Media Electronic Reporting Regulation, 40 CFR part 3.

Most of the commenters were supportive of the proposed amendments for electronically submitting state plans. However, a few commenters expressed that EPA should provide an option to submit state plans in paper format. The EPA has determined that submitting state plans electronically is more efficient and less burdensome than paper submittals. States already submit state implementation plans electronically via SPeCS so there should be little to no additional burden associated with using it for state plans. Additionally, having some states submit state plans via SPeCS and other states mail hard-copy plans to regional offices would undermine many of the efficiencies provided to the EPA through the use of electronic submission and could result in confusion. One commenter recommended adding language to clarify that a Negative Declaration letter submitted in accordance with 40 CFR 60.23a(b) can also be submitted via SPeCS. The EPA agrees with the need to add the electronic submittal language to 40 CFR 60.23a(b) identified by the commenter and has added the language in the final rule so that the states submit the Negative Declaration letter using the SPeCS, or through an analogous electronic reporting tool provided by the EPA for the submission of any plan required by this subpart.

The EPA is therefore finalizing the requirements for electronic submittal of state plans in 40 CFR 60.23a(a)(1) and (3). As finalized, 40 CFR 60.23a(a)(1) provides: ‘‘The submission of such plan shall be made in electronic format according with § 60.23a(a)(3) or as specified in an applicable emission guideline.’’ The regulation at 40 CFR 60.23a(a)(3) in turn contains the general requirements associated with the electronic submittal of a state plan in subpart Ba via the use of SPeCS or through an analogous electronic reporting tool provided by the EPA for the submission of any plan required by subpart Ba. The EPA is also including at 40 CFR 60.23a(a)(3) language to specify that states are not to transmit confidential business information (CBI) through SPeCS. Even though state plans submitted to the EPA for review and approval pursuant to CAA section 111(d) through SPeCS are not to contain CBI, the language at 40 CFR 60.23a(a)(3) also addresses the submittal of CBI in the event there is a need for such information to be submitted to the EPA.

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[151] 40 CFR 62.1100(b)(7); 85 FR 1121 (Jan. 9, 2020); see also ‘‘Appendix E: Comparison of the Major Provisions of the Emission Guidelines and California’s Landfill Methane Regulation,’’ EPA–R09–OAR–2019–0393–0008 (technical support document for EPA action on California’s CAA section 111(d) state plan to implement the EG for landfill gas from municipal solid waste landfills).

[152] 87 FR 79206.

Any other specific requirements associated with the electronic submittal of a particular state plan will be provided within the corresponding EG. The requirements for electronic submission of CAA section 111(d) state plans in EGs will ensure that these Federal records are created, retained, and maintained in electronic format. Electronic submittal will also improve the Agency's efficiency and effectiveness in the receipt and review of state plans. The electronic submittal of state plans may also provide continuity in the event of a disaster like the one our nation experienced with COVID–19.

G. Other Proposed Modifications and Clarifications

1. Standard of Performance and Compliance Flexibility

a. Definition of Standard of Performance

The EPA proposed amendments to 40 CFR 60.21a(f) and 60.24a(b) to clarify that the definition of ''standard of performance'' allows for state plans to include standards in the form of an allowable mass limit of emissions. As explained in the notice of proposed rulemaking,[153] the amendments were intended to harmonize these regulatory definitions with the definitions of ''emission limitation'' and ''emission standard'' in CAA section 302(k), which is ''a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction, and any design, equipment, work practice, or operational standard promulgated under this chapter.'' While the EPA had intended the phrase ''allowable rate or limit of emissions'' in the existing regulatory definitions to encompass the full range of forms included in the statute, to eliminate any potential confusion the Agency proposed to make this explicit.

Most comments received on the proposed revision to the definition of ''standard of performance'' were in support of these amendments. Some commenters pointed out that the revision would be consistent with the statutory definition in CAA section 302(k) and many expressed approval that the revised definition would clearly allow for standards of performance to take the form of mass-based emission limits. Several commenters stressed that, while they supported the proposed definition of standard of performance for subpart Ba, the appropriate form of the standard of performance in any particular EG must be determined in the context of that EG. Some commenters expressed concern that the proposed revision would allow the EPA to define the BSER as a trading program for any source sector, or for states and the EPA to impose emissions averaging and trading programs in CAA section 111(d) plans.

The EPA is finalizing amendments to 40 CFR 60.21a(f) and 60.24a(b) as proposed. The Agency's interpretation of CAA section 111 with regard to emissions trading or averaging is a separate matter that is discussed in section III.G.1.b. of this preamble; it is reiterated that the revisions to the definition of standard of performance are being made to align it with the statutory definition of emission limitation and emission standard in CAA section 302(k) for the purpose of these general implementing regulations. The EPA agrees with commenters that the appropriate form of the standard of performance in any particular EG must be determined in the context of that EG, and the EPA may choose to prescribe the acceptable form or forms of the standard of performance in an individual EG. In addition to finalizing the proposed amendments to 40 CFR 60.21a(f) to clarify that the term ''an allowable rate or limit of emissions'' means ''an allowable rate, quantity, or concentration of emissions'' of air pollutants, the EPA is also finalizing its proposed removal of the phrase ''but not limited to'' from 40 CFR 60.21a(f) as unnecessary and potentially confusing verbiage that is redundant of the word ''including,'' particularly where the definition already identifies a wide breadth of potential standards that may be included in a state plan. Moreover, the EPA is finalizing amendments to the definition of standard of performance under 40 CFR 60.24a(b) to read ''. . . in the form of an allowable rate, quantity, or concentration of emissions'' rather than ''. . . either be based on allowable rate or limit of emission.''

b. Compliance Flexibilities, Including Trading or Averaging

The EPA is finalizing its proposal that CAA section 111(a) and (d) cannot be interpreted, by their terms, to limit the types of controls that states, in their state plans, may authorize their sources to adopt to at-the-source, and thereby preclude states from authorizing their sources flexibilities such as trading or averaging. Under the provisions of CAA section 111(a) and (d), and consistent with the federalism principles that underlie the CAA, states have broad authority to determine the types of control measures for their sources, including trading or averaging, although the EPA may establish constraints to protect the integrity of particular EGs. The EPA is also finalizing its proposal that CAA section 111 cannot be interpreted, by its terms, to limit the ''best system of emission reduction . . . adequately demonstrated'' (BSER) to at-the-source measures. As the EPA explains, many control measures that the EPA has determined to be the BSER in prior rules have outside-the-source components. The EPA is finalizing its repeal of the ACE Rule's contrary interpretations of CAA section 111.

In the proposal, the EPA provided a brief summary of the applicable CAA provisions, the ACE Rule, the D.C. Circuit's decision reversing the ACE Rule, and the U.S. Supreme Court's decision vacating the D.C. Circuit's vacatur of the ACE Rule.[154] For convenience, parts of that summary are reproduced here.

i. *CAA section 111.* Under CAA section 111(d)(1), each state is required to submit to the EPA ''a plan which . . . establishes standards of performance for any existing source'' that emits certain types of air pollutants, and which ''provides for the implementation and enforcement of such standards of performance.'' Under CAA section 111(a)(1), a ''standard of performance'' is defined as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.''

ii. *Rulemaking and caselaw.* In the Clean Power Plan (CPP), the EPA interpreted the term ''system'' in CAA section 111(a)(1) to be broad and therefore to authorize the EPA to consider a wide range of measures from which to select the BSER.[155] Similarly, the CPP took the position that states had broad flexibility in choosing compliance measures for their state plans.[156] The CPP went on to determine that generation shifting qualified as the BSER,[157] and that states could include trading or averaging programs in their state plans for compliance.[158]

The ACE Rule included the repeal of the CPP. It interpreted CAA section 111 so that the type of ''system'' that the EPA may select as the BSER is limited to a control measure that could be

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[153] 87 FR 79176, 79206–07 (Dec. 23, 2022).

[154] 87 FR 79176, 79207–08 (Dec. 23, 2022).

[155] 80 FR 64662, 64720 (October 23, 2015).

[156] See, *e.g.,* id. at 64887.

[157] Id. at 64707.

[158] Id. at 64840.

applied at each source (that is, inside the fenceline of each source) to reduce emissions at each source.[159] The ACE Rule also concluded that the compliance measures the states include in their plans must ''correspond with the approach used to set the standard in the first place,'' [160] and therefore must also be limited to inside-the-fenceline measures that reduce the emissions of each source. For these reasons, the ACE Rule invalidated the CPP's generation-shifting system as the BSER, on grounds that it was an outside the source measure, and precluded states from allowing their sources to trade or average to demonstrate compliance with their emission standards.[161]

In 2021, the D.C. Circuit vacated the ACE Rule.[162] The court held, among other things, that CAA section 111(d) does not limit the EPA, in determining the BSER, to at-the- source measures.[163] The court further held that the ACE Rule's premise for viewing compliance measures as limited to at the source measures, which is that BSER measures are so limited, was invalid for the same reason. The court indicated that while requiring symmetry between the nature of the BSER and compliance measures ''would be reasonable'' where necessary to preserve the environmental outcomes a particular BSER was designed to achieve, a universal restriction on compliance measures could not be sustained by policy concerns that were not similarly universal.[164]

In 2022, the U.S. Supreme Court reversed the D.C. Circuit's vacatur of the ACE Rule's embedded repeal of the Clean Power Plan.[165] The Supreme Court made clear that CAA section 111 authorizes the EPA to determine the BSER and the amount of emission limitation that state plans must achieve.[166] However, the Supreme Court invalidated the CPP's generation-shifting BSER under the major question doctrine, explaining that the term ''system'' does not provide the ''clear congressional authorization'' needed to support a BSER ''of such magnitude and consequence.'' [167] The Court declined to address the D.C. Circuit's decision that the text of CAA section 111 did not limit the type of ''system'' the EPA could consider as the BSER to at-the-source measures.[168] Nor did the Court rule on the scope of the states' compliance flexibilities.

iii. *Proposal.* In the proposal, the EPA stated that it has reconsidered the ACE Rule's interpretation of the compliance flexibilities available to states under CAA section 111 and that it was proposing to disagree with the rule's view that trading or averaging are universally precluded [169] and that state plan compliance measures must always correspond with the approach the EPA uses to set the BSER. The EPA added, however, that the flexibility that CAA section 111(d) grants to states in adopting measures for their state plans is not unfettered; rather, CAA section 111(d)(2) requires the EPA to review state plans to ensure that they are ''satisfactory,'' and the EPA may conclude in particular emission guidelines that limiting the types of control measures states may authorize their sources to adopt, including precluding trading or averaging, are necessary to protect the environmental outcomes of the emission guidelines.[170]

In addition, the EPA also proposed to reject the ACE Rule's interpretation that various provisions in CAA section 111 limit the type of ''system'' that may qualify as the BSER to at-the-source measures.[171] The EPA explained that it proposed to agree with the part of the D.C. Circuit's decision in *American Lung Ass'n,*[172] that rejected the ACE Rule's at-the-source statutory interpretation. The EPA added that it recognized that the Supreme Court, in *West Virginia,* did impose limits, through the application of the major question doctrine, on the type of ''system'' that may qualify as the BSER.[173] The EPA made clear that it was not proposing to address the scope of the limits that may result from application of the major question doctrine, and thus was not proposing to address whether it could include trading or averaging as part of the BSER, or to identify any particular control mechanism that could or could not be part of a specific BSER, in light of those limits. Instead, the EPA stated that it may address further those limits, and their implications for the legality of particular systems of emission reduction and state compliance measures, in future emission guidelines.[174]

iv. *The EPA's finalized interpretation of state authority to grant compliance flexibilities.* The EPA is finalizing its proposal that, contrary to the position of the ACE Rule, CAA section 111 does not preclude states from including compliance flexibilities such as trading or averaging for their sources in their state plans, although in particular emission guidelines the EPA may limit those flexibilities if necessary to protect the environmental outcomes of the guidelines. The EPA is also rescinding the related ACE Rule interpretation that CAA section 111 requires that state plan measures be symmetrical to the types of measures the EPA included in the BSER.

Most commenters agreed with the proposal that CAA section 111 does not preclude states from including compliance flexibilities in their state plans. However, several commenters disagreed and submitted adverse comments. Some commenters stated that *West Virginia* is clear that the EPA cannot include generation-shifting as the BSER, and then argued that the EPA cannot include trading as part of the BSER because trading entails generation shifting, and then further argued that for emission guidelines applicable to electric generating units, the EPA cannot authorize trading as a compliance mechanism because trading incentivizes generation shifting to occur and only works if generation shifting does occur. As explained further below, the EPA does not believe that these adverse comments cast doubt on the rationale that it gave in the proposal for why states have the authority to allow compliance flexibilities such as trading or averaging.[175] The EPA continues to agree with the reasoning in *American Lung Ass'n,*[176] in rejecting the ACE Rule's limitations on those measures.

To review the reasons that the ACE Rule gave for asserting that trading or averaging across designated facilities is inconsistent with CAA section 111: The ACE Rule stated that those options would not necessarily require any emission reductions from designated

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[159] 84 FR 32520, 32523–24 (July 8, 2019).

[160] Id. at 32556.

[161] Id. at 32556–57.

[162] *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021).

[163] *Id.* at 944–51

[164] *Id.* at 957–58.

[165] *West Virginia* v. *EPA,* 142 S. Ct. 2587 (2022).

[166] *Id.* at 2601–02.

[167] *Id.* at 2614–16 (internal quotation marks omitted).

[168] *See id.* at 2615 (''We have no occasion to decide whether the statutory phrase 'system of emission reduction' refers exclusively to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as the BSER.'' (emphasis omitted)).

[169] With respect to averaging, the ACE Rule noted that the D.C. Circuit has recognized that the EPA may have statutory authority under CAA section 111 to allow plant-wide emissions averaging, *See U.S. Sugar* v. *EPA,* 830 F.3d 579, 627 n.18 (D.C. Cir. 2016) (pointing to the definition of ''stationary source''), but stated that the Agency's determination that individual EGUs are subject to regulation under ACE precludes the Agency from attempting to change the basic unit from an EGU to a combination of EGUs for purposes of ACE implementation.

[170] 87 FR 79208.

[171] 84 FR 32556.

[172] 985 F.3d at 944–51.

[173] 142 S. Ct. at 2615–16.

[174] 87 FR 79208.

[175] Id.

[176] 985 F.3d at 957–58.

facilities and may not actually reflect application of the BSER. The ACE Rule explained that ''state plans must establish standards of performance—which by definition 'reflects . . . the application of the best system of emission reduction,' ''[177] and then asserted that implementation and enforcement of such standards should be based on improving the emissions performance of sources to which a standard of performance applies. The ACE Rule added that trading or averaging would effectively allow a state to establish standards of performance that do not reflect application of the BSER, and gave, as an example, the possibility that under a trading program, a single source could potentially shut down or reduce utilization to such an extent that its reduced or eliminated operation generates sufficient allowances for a state's remaining sources to meet their standards of performance without themselves making any emission reductions from any other source. The ACE Rule asserted that this compliance strategy would undermine the EPA's determination of the BSER.[178]

This interpretation of CAA section 111 is unduly strained and the EPA rejects it. The provisions of CAA section 111(d) by their terms do not affirmatively bar states from considering trading or averaging as a compliance measure where appropriate for a particular emission guideline. Under CAA section 111(d)(1), each state must ''establish[ ],'' ''implement[ ],'' and ''enforce[ ]'' ''standards of performance for any existing source.'' A state plan may ''establish[ ]'' a standard of performance for each source that constitutes an emissions standard that reflects the amount of emission reduction that the source could achieve by applying the BSER, but the state may also allow measures like trading or averaging as potential means of compliance. Nothing in the text of CAA section 111 precludes states from considering a source's acquisition of allowances as part of a trading program in ''implement[ing]'' and ''enforce[ing]'' a standard of performance for that particular source, so long as the state plan achieves the required overall level of emission reductions.[179] CAA section 111(d)(1) requires only that each source comply with its standard, not that each source do so through applying the BSER. By the same token, contrary to the ACE Rule,[180] CAA section 111(d)(1) does not limit the states to compliance measures that are symmetrical to what the EPA determined to be the BSER unless necessary to preserve the environmental outcomes a particular system was designed to achieve.

For further support for the interpretation that CAA section 111 does not preclude states from authorizing compliance flexibilities such as trading or averaging, the EPA notes that CAA section 111(d)(1) requires a ''procedure similar to that provided by [CAA section 110].''[181] Consideration of the CAA section 110 framework reinforces the absence of any mandate that states consider only compliance measures that apply at and to an individual source. ''States have 'wide discretion' in formulating their plans'' under section 110.[182] The EPA has authorized trading programs in CAA section 110 SIPs for decades. See Economic Incentive guidance.[183]

Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion in establishing control requirements for their sources. As the U.S. Supreme Court has explained, CAA section 111(d) ''envisions extensive cooperation between Federal and state authorities, generally permitting each State to take the first cut at determining how best to achieve EPA emissions standards within its domain.''[184]

This interpretation is also consistent with the EPA's consistent views prior to the ACE Rule. The EPA authorized trading or averaging as compliance methods in the 2005 Clean Air Mercury Rule for coal-fired EGUs,[185] and the 2015 Clean Power Plan (CPP).[186]

It must be emphasized that the EPA retains an important role in reviewing state plans for adequacy. Under CAA section 111(d)(2)(A), the EPA must determine that the state plan is ''satisfactory'' and, if the state plan is not satisfactory or if the state does not submit a state plan, the EPA must promulgate a plan that establishes Federal standards of performance for the State's existing sources. Thus, the flexibility that CAA section 111(d)(1) grants to states in adopting measures for their state plans is not unfettered. As the Supreme Court stated in *West Virginia,* ''The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved.''[187] The Court further stated that state plans must contain ''emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA.''[188] Thus, the EPA retains the authority to ensure that the permissible level of pollution is not exceeded by any state plan. If the EPA considers that compliance flexibility measures would compromise the ability of the state plan to achieve the environmental outcomes the best system could achieve, the EPA may, in the emission guidelines, preclude such measures or otherwise conclude that the state plan is not satisfactory.

In *West Virginia* v. *EPA,* the Supreme Court did not directly address the state's authority to determine their sources' control measures. Although the Court did hold that constraints apply to the EPA's authority in determining the BSER, the Court's discussion of CAA section 111 is consistent with the EPA's interpretation that the provision does not preclude states from granting sources compliance flexibility.

At the outset of the decision, the Court made clear CAA section 111

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[177] This paraphrasing by the ACE Rule of the CAA section 111(a)(1) definition of ''standard of performance'' is incomplete—a ''standard of performance'' ''reflects the degree of emission limitation achievable through the application of the best system of emission reduction.''

[178] 84 FR 32557.

[179] This overall level of emissions reduction is the level that would be achieved if each source were to apply the BSER.

[180] 84 FR 32556 (ACE Rule states that one reason why CAA section 111 precludes states from authorizing trading or averaging is that ''[a]pplying an implementation approach that differs from standard-setting would result in asymmetrical regulation'').

[181] *See* CAA section 111(d)(2)(A) (referring to CAA section 110(c)), 111(d)(2)(B) (referring to enforcement of state implementation plans (SIPs)).

[182] *Alaska Dep't of Envtl. Conservation* v. *EPA,* 540 U.S. 461, 470 (2004) (citation omitted); *see Union Elec. Co.* v. *EPA,* 427 U.S. 246, 269 (1976) (''Congress plainly left with the States, so long as the national standards were met, the power to determine which sources would be burdened by regulation and to what extent.''); *Train* v. *Natural Res. Def. Council, Inc.,* 421 U.S. 60, 79 (1975) (''[S]o long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation.'').

[183] The ACE Rule stated that the reference in CAA section 111(d)(1) to CAA section 110 was limited to the procedure under which states shall submit plans to the EPA, and asserted that it does not imply anything about implementation mechanisms available under CAA section 111(d). 84 FR 32557. The EPA believes that the several references to CAA section 110 in CAA section 111(d)(1) and (2), as noted in the accompanying text, support the view that Congress intended that state plans under CAA section 111(d) would be similar to state plans under CAA section 110, including retaining the authority to grant sources compliance flexibility in appropriate circumstances.

[184] *American Elec. Power Co.* v. *Connecticut,* 564 U.S. 410, 428 (2011) (citations omitted).

[185] 70 FR 28606, 28617 (May 18, 2005), vacated on other grounds, *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008), *see* 40 CFR 60.24(b)(1) (2005) (providing that a state's ''[e]mission standards [may] be based on an allowance system), repealed in the ACE Rule.

[186] 80 FR 64662, 64840 (October 23, 2015), repealed by the ACE Rule. 87 FR 79208.

[187] 142 S. Ct. at 2602.

[188] Id.

provides different roles for the EPA and the States:

> Although the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d). The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, ''the [BSER]. . . . The States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA.[189]

The Court was clear that the focus of the case was exclusively on the EPA's role, that is, whether the EPA acted within the scope of its authority in establishing the BSER.[190] The Court applied the major question doctrine to hold that the generation-shifting BSER that the EPA promulgated in the CPP exceeded the constraints of the CAA section 111 BSER provisions, in light of ''separation of powers principles and a practical understanding of legislative intent.'' [191] The Court did not identify any constraints on the states in establishing standards of performance to their sources, and its holding and reasoning cannot be extended to apply such constraints. In fact, the Supreme Court at least implicitly recognized that CAA section 111(d) does not preclude states from authorizing sources compliance flexibility when the Court observed that a new or modified source ''may achieve [the EPA-determined] emissions [standard] any way it chooses.'' [192] There is no reason why existing sources should have less flexibility.

It should also be noted that the adverse commenters described above are incorrect in their view that trading necessarily results in generation shifting and that the logic of the *West Virginia* decision precludes any such generation shifting. As just noted, the reasons why the Court held that the CPP's generation-shifting BSER violated the major question doctrine and thus was invalid have no application to states in developing state plans. In addition, the Court was clear that a BSER that has the incidental effect of resulting in generation shifting would not, on those grounds, violate the major question doctrine. The Court emphasized that ''there is an obvious difference between (1) issuing a rule that may end up causing an incidental loss of coal's market share, and (2) simply announcing what the market share of coal, natural gas, wind, and solar must be, and then requiring plants to reduce operations or subsidize their competitors to get there.'' [193] The second option is what the Court viewed the CPP's generation-shifting BSER as attempting to do, which thereby triggers the major question doctrine. But, as a coalition of companies that operate electricity generation as well as transmission and distribution systems commented, the Court ''evinced no general concern about option 1, which is an inevitable consequence of regulation within the power sector, in which all sources of emissions are interconnected and increase or decrease their generation based upon demand for electricity and other sources' availability.'' [194] If the Court in *West Virginia* had little concern with the EPA determining a BSER that has the incidental effect of shifting generation, there is no basis for reading the case to preclude a state from adopting trading measures in its state plan on grounds that those measures may have the incidental effect of shifting generation. In any event, in many instances, trading simply apportions the cost of controls between the sources engaged in the transaction, and does not result in generation shifting. To illustrate, assume that the EPA promulgates an emissions guideline that determines as the BSER the installation by a source of control equipment that captures 40 percent of its emissions of a pollutant. Assume further that a state allows two of its designated facilities of comparable size and emissions to engage in an emission trade, so that one source installs control equipment that captures 80 percent of its emissions, and the other one does not put on control equipment but purchases allowances from the first one that fund half the costs of the first one's control equipment. This type of emissions trade would not necessarily give rise to generation shifting.

For the reasons noted above, the EPA is rescinding the ACE Rule's interpretation that state plans may not include trading or averaging or other compliance flexibilities.

v. *The EPA's finalized interpretation of BSER.* The EPA is also finalizing its proposal to rescind the ACE Rule's interpretation that CAA section 111, by its plain meaning, limits the BSER to at-the-source measures. The ACE Rule's interpretation is incorrect. In addition, as a practical matter, it could call into question many of the EPA's determinations in prior CAA section 111 rules that well-established control measures, including clean fuels and add-on control technology, qualified as the BSER. This is because many of these traditional measures are not entirely at-the-source controls, but also include outside-the-source components. *West Virginia* does not preclude the EPA from rescinding the ACE Rule interpretation because although the Supreme Court held that the CPP's generation-shifting BSER violated the major question doctrine, Court declined to address the ACE Rule's interpretation of CAA section 111.[195]

To repeat for convenience the key requirements for determining the BSER under CAA section 111: each state must establish ''standards of performance for any existing source'' of certain types of air pollutants, under CAA section 111(d)(1); a ''standard of performance'' is defined as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated, under CAA section 111(a)(1);'' and ''existing source'' is defined as a ''stationary source,'' which, in turn, is defined, in relevant part, as ''any building, structure, facility or installation,'' under CAA section 111(a)(6) and (a)(3).

The ACE Rule interpreted CAA section 111 to limit, by its plain language, the type of ''system'' that the EPA may select as the BSER to control measures that can be applied at each source to reduce that source's emissions.[196] Specifically, the ACE Rule argued that the requirements in CAA section 111(d)(1), (a)(3), and (a)(6) that each state establish a standard of performance ''for'' ''any existing source'' (in the singular), defined, in general, as any ''building . . . [or] facility,'' and the requirements in CAA section 111(a)(1) that the standard of performance reflect a degree of emission limitation that is ''achievable'' through the ''application'' of the BSER, by their terms, impose this limitation.[197]

Upon reconsideration, the EPA concludes that, contrary to the ACE Rule, CAA section 111(d) does not limit the EPA to at-the-source measures in determining the BSER. The CAA section

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[189] *West Virginia* v. *EPA,* 142 S.Ct. at 2601–02 (citations omitted).

[190] Id. at 2600 (''The question before us is whether this broad[ ] conception of EPA's authority [to determine the BSER] is within the power granted to it by the Clean Air Act.'').

[191] Id. at 2609.

[192] Id. at 2601.

[193] Id. at 2613 n.4.

[194] Comment Letter from Energy Strategy Coalition on ''Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), EPA–HQ–OAR–2021–0527–0088 at 6.

[195] 142 S.Ct. at 2615–16.

[196] 84 FR 32523–24.

[197] Id. at 32556–57.

111 requirement that each state establish a standard of performance ''for'' any existing ''building . . . [or] facility,''' means simply that the state must establish standards applicable to each regulated stationary source; and the requirement that the standard reflect a degree of emission limitation ''achievable'' through the ''application'' of the BSER means that the source must be able to apply the system to meet the standard. None of these requirements by their plain language mandate that the BSER is limited to some measure that each source can apply to its own facility to reduce its own emissions in a specified amount. That the standards must be ''for'' a source does not mean that the control measures that form the basis for the standard are limited to measures that apply at the source or that all emission reductions from the control measures must occur at the source.

The ACE Rule also argued that as a matter of grammar, the term ''application,'' which is derived from the verb, ''to apply,'' requires an indirect object, and, further, that the phrase ''application of the best system of emission reduction'' has, as the unstated indirect object, an existing source. From this premise, the ACE Rule concluded that the phrase must be read to refer to the application of the best system of emission reduction at or to the existing source itself.[198] But this premise is incorrect. As the D.C. Circuit explained in *American Lung Ass'n,* ''application'' is a noun, and ''the phrase 'application of the best system of emission reduction' is what is called a nominalization, a 'result of forming a noun or noun phrase from a clause or a verb.' '' [199] The court further explained that ''[g]rammar assigns direct or indirect objects only to verbs—not nouns. No objects are needed to grammatically complete the actual statutory phrase.'' [200] In any event, the fact that any such indirect object is unstated itself contradicts the ACE Rule's conclusion that CAA section 111 by its plain language mandates that the BSER must be limited to at-the-source measures.[201]

It should also be noted that CAA section 111(a)(1) provides that when the EPA determines the BSER, it must ''tak[e] into account'' ''cost'' and ''any nonair quality health and environmental impact and energy requirements.'' As the ACE Rule itself recognized, the EPA may consider the application of these requirements on a ''sector-wide, region-wide or nationwide basis.'' [202] As discussed below, the reference to ''nonair quality health and environmental impact'' may encompass to offsite impacts of control measures. Thus, these provisions contradict the ACE Rule's argument that CAA section 111(d)(1) and (a), by its plain language, limits the BSER to at-the-source measures. By the same token, the term ''achievable'' refers to the ''degree of emission limitation'' that must be ''reflect[ed]'' in the standards of performance ''through the application of the [BSER].'' This term does not, by its plain language, limit the BSER to at-the-source measures.

Importantly, it should be emphasized that the ACE Rule's interpretation that the provisions of CAA section 111(d)(1) and (a) by their plain language require that the EPA identify as the BSER control measures that apply at-the-source would also impose the same limit on the state, that is, limit the state to authorizing its sources to comply with their standards only through at-the-source measures. As a result, this interpretation would preclude the state from allowing its sources compliance flexibilities such as trading or averaging. In fact, the ACE Rule argued that states were limited in that manner. For the reasons noted above, limiting the states in that manner is contrary to the provisions of CAA section 111(d) and the framework of cooperative federalism that CAA section 111(d) establishes.

The ACE Rule also argued that the legislative history of the 1970 CAA Amendments confirms the rule's at-the-source interpretation for BSER.[203] The rule read the legislative history to indicate that the House and Senate bills that led to the adoption of CAA section 111 ''contemplated only control measures that would lead to better design, construction, operation, and maintenance of an individual source. . . .'' [204] The EPA disagrees with this interpretation of the legislative history. The ACE Rule itself acknowledged that the 1970 CAA Amendments legislative history also included broader language in describing the types of measures that were to provide the basis for the standards of performance.[205] In addition, the ACE Rule went on to narrow its argument about legislative history to saying that the 1990 CAA Amendments made clear only that generation-shifting was precluded.[206] *Id.* at 32526 n.62. Thus, the EPA finds that the legislative history cannot be read to confirm the interpretation that section 111(d) and (a)(1), by their plain language, limit the BSER to at-the-source measures.

There is another reason why the ACE Rule's interpretation is incorrect: it appears to be inconsistent with many EPA determinations in previous CAA section 111 rulemakings that certain control measures qualified as the BSER. This is because although those measures apply at the source and reduce

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[198] Id. at 32524.

[199] 985 F.3d at 948 (citations omitted).

[200] *Id.*

[201] The ACE Rule stated that the CAA provisions concerning the ''best available control technology'' (BACT) provide a CAA structural argument that supports its interpretation that CAA section 111 limits BSER to at-the-source measures. CAA section 165(a)(4) provides that construction and modification of major stationary sources of a pollutant are subject to BACT, as defined under CAA section 169(3), for each pollutant subject to regulation under the CAA. The definition of BACT provides, ''In no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to [CAA] section [111] or [112].'' The ACE Rule pointed to the EPA's reading of this sentence to mean that section 111 standards of performance ''operate as a floor to BACT.'' The ACE Rule asserted that, under the definition of BACT, control measures are limited to at-the-source measures. The ACE Rule reasoned that section 111 standards of performance must, by operation of the structure of the CAA, also be interpreted to be limited to at-the-source measures. 84 FR 32525. Upon further review, the EPA rejects this argument. The EPA considers whether CAA section 169(3) should be interpreted to limit BACT to at-the-source measures to be an open question, and is not addressing it at this time. Even if BACT were so limited, the ACE Rule did not demonstrate that any BACT requirement that a particular source would be subject to would be incompatible with any standard of performance that source would also be subject to. Section 169(3) by its plain language provides that the application of BACT may not result in exceedances of any applicable standard of performance.

The ACE Rule also focused on statements in the CPP that it asserted conflated the terms ''application'' and implementation, as well as ''source'' and owner/operator; and that defined ''system'' broadly. The rule asserted that the CPP strained the interpretation of CAA section 111 in those ways to justify determining generation-shifting as the BSER. 84 FR 32526–29. Regardless of whether those arguments have merit with respect to the generation-shifting, they are not relevant to the position that the EPA is taking in the present action that the ACE Rule erred in interpreting CAA section 111 by its terms to limit the BSER to at-the-source measures. It should also be noted that the CPP's recognition that as a practical matter, it is the owner/operator who takes actions to apply control measures and assure that the source's emissions meet the standard is a matter of common sense and applies as well to all control measures, whether at the source or outside the source. The ACE Rule itself referred to the ''owner or operator'' as the entity that ''must be able to achieve an applicable standard by applying the BSER . . . .'' 84 FR 32524.

[202] 84 FR 32534 n.152 (referring to application of ''energy requirements'').

[203] 84 FR 32525–26.

[204] *Id.* at 32526.

[205] *Id.* at 32526 n.61. The ACE Rule argued that the canon of *ejusdem generis* required that those broader terms be interpreted to denote at-the-source measures but e*jusdem generis* is an aid in statutory construction and should not be used to narrow the meaning of a statute beyond its intention. Karl N. Llwellyn, Remarks on the Theory of Appellate Decision and the Rules or Canons about how Statutes are to be Construed, 3 Vanderbilt L. Rev. 395, 405 & n.46 (1950).

[206] *Id.* at 32526 n.61.

emissions at the source, they also have components that are outside the source. In *West Virginia,* the Supreme Court recognized that the EPA had, in prior rules, identified as the BSER these ‘‘‘more traditional air pollution control measures.’ ’’[207] The Court made this point as part of its reasoning that the CPP's generation-shifting BSER—which the Court stated differed from these traditional measures—raised a major question. The Court quoted the CPP as describing these traditional measures as ‘‘‘efficiency improvements, fuel-switching,’’ and ‘add-on controls.’ ’’ [208] The Court noted that these types of controls have several characteristics: they ‘‘reduce pollution by causing the regulated source to operate more cleanly.’’ [209] They ‘‘ ‘allow[ ] regulated entities to produce as much of a particular good as they desire provided that they do so through an appropriately clean (or low-emitting) process.’ ’’ ’[210] They are ‘‘technology-based . . . [and] focuse[d] on improving the emissions performance of individual sources.’’ [211]

However, many of these traditional controls also have components that are outside the source. One example includes what the Court, quoting the CPP, identified as ‘‘fuel-switching.’’ [212] Fuel-switching entails the use of lower-emitting fuels. These include fuels that have been cleaned, or processed, to reduce their level of pollutants,[213] such as coal or oil that has been desulfurized. Desulfurization reduces the amount of sulfur in the fuel, which means that the fuel can be combusted with fewer SO_2 emissions. Importantly, the process of desulfurization typically occurs off-site and is undertaken by third parties. Congress itself recognized this in the 1977 CAA Amendments. Specifically, Congress revised CAA section 111(a)(1) to identify the basis for standards of performance for new fossil fuel-fired stationary sources as a ‘‘technological system of continuous emission reduction,’’ including ‘‘precombustion cleaning or treatment of fuels.’’ [214] The 1977 House Committee report stated that fuel cleaning includes ‘‘oil desulfurization at the refinery.’’ [215] The report added that fuel cleaning includes ‘‘various coal-cleaning technologies,’’ which generally are also conducted off-site by third parties.[216] As noted above, in the 1990 CAA Amendments, Congress eliminated many of the restrictions and other provisions added in the 1977 CAA Amendments by largely reinstating the 1970 CAA Amendments' definition of ‘‘standard of performance.’’ Nevertheless, there is no indication that in doing so, Congress intended to preclude the EPA from considering fuel cleaning off-site by third parties. In fact, the EPA's regulations promulgated after the 1990 CAA Amendments continue to impose standards of performance that are based on coal cleaning off-site by third parties.[217]

A second example includes what the Court, again quoting the CPP, identified as ‘‘add-on controls.’’ [218] These controls include air pollution control devices that are installed at the unit. They routinely operate by removing air pollutants from a unit's emission stream and capturing them as a liquid or solid. For example, a baghouse is an add-on control device that captures particulate matter by trapping particles as a dust, which must then be disposed of.[219] Another add-on control device, flue-gas desulfurization, ‘‘scrubs’’ acid gases like sulfur dioxide from emissions using a chemical sorbent that reacts with the pollutant to generate a liquid slurry (wet scrubbing) or solid residue (dry scrubbing). These captured pollutants must then be disposed as solid wastes, discharged as wastewater, or otherwise managed or reused.[220] The same is true for carbon capture and sequestration (CCS): the carbon capture control device scrubs CO_2 from the flue gas stream using a solvent; and the CO_2 must then be stored underground.[221] Downstream management of captured pollutants is thus a commonplace feature of CAA section 111 standards.[222] Downstream management of captured pollutants is thus a commonplace feature of CAA section 111 standards.[223]

Indeed, CAA section 111(a)(1) by its terms recognizes that ‘‘system[s] of emission reduction’’ may entail off-site disposition of pollutants. The provision states that the EPA must consider ‘‘nonair quality health and environmental impact’’ when determining the BSER. Congress adopted this phrase in the 1977 CAA Amendments.[224] As the legislative history stated, Congress added this phrase so that ‘‘environmental impacts would be required to be considered in determining best technology which has been adequately demonstrated.’’ [225] In making this addition, Congress codified the D.C. Circuit's holding in *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 438–39 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).[226] In *Essex Chem. Corp.,* the D.C. Circuit required that EPA ‘‘take into account counter-productive environmental effects’’ when determining whether a control measure qualifies as the BSER, including ‘‘disposal problems’’ related to the control measure's captured pollutants. The Court remanded the NSPS at issue because there was no evidence that the EPA had considered ‘‘the significant land or water pollution potential

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[207] 142 S.Ct.at 2611 (citing 80 FR 64662, 64784 (Oct. 23, 2015)).

[208] *Id.* (citing 80 FR 64784).

[209] 142 S.Ct. at 2610.

[210] *Id.* (quoting 80 FR 64738).

[211] *Id.* at 2611.

[212] *Id.*

[213] EPA considered fuel cleaning to be within the scope of the best system of emission reduction beginning immediately after the adoption of the 1970 CAA Amendments. *See* U.S. EPA, *Background Information for Proposed New-Source Performance Standards: Steam Generators, Incinerators, Portland Cement Plants, Nitric Acid Plants, Sulfuric Acid Plants,* Office of Air Programs Tech. Rep. No. APTD–0711, p. 7 (Aug. 1971) (indicating the ‘‘desirability of setting sulfur dioxide standards that would allow the use of low-sulfur fuels *as well as fuel cleaning,* stack-gas cleaning, and equipment modifications’’ (emphasis added)).

[214] 1977 CAA Amendments, section 109, 91 Stat. 700; see also CAA section 111(a)(7).

[215] H.R. Rep. No. 95–294 (May 12, 1977), 1977 CAA Legis. Hist. at 2655 (emphasis added).

[216] *Id.* EPA recognized in a regulatory analysis of new source performance standards for industrial-commercial-institutional steam generating units that the technology ‘‘requires too much space and is too expensive to be employed at individual industrial-commercial-institutional steam generating units.’’ U.S. EPA, *Summary of Regulatory Analysis for New Source Performance Standards: Industrial-Commercial-Institutional Steam Generating Units of Greater than 100 Million Btu/hrHeat Input,* EPA–450/3–86–005, p. 4–4 (June 1986).

[217] 40 CFR 60.49b(n)(4); *see also* Amendments to New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units and Industrial-Commercial-Institutional Steam Generating Units; Final Rule, 72 FR 32742 (June 13, 2007).

[218] 142 S.Ct. at 2611.

[219] *See Sierra Club* v. *Costle,* 657 F.2d 298, 375 (D.C. Cir. 1981).

[220] *See id.* at 323–24 n.69; see also 80 FR 21303, 21340 (April 17, 2015) (governing off-site disposal of solid wastes captured by air pollution controls at steam units).

[221] 80 FR 64549, 64555 (describing CCS and comparing CCS pollutant disposition to particulate or wet scrubber pollutant disposition).

[222] *See, e.g.,* 80 FR 64582–90 (requiring that an EGU that captures CO_2 assure that it is transferred to an entity that will dispose of it appropriately; generally describing oversight of CO_2 storage; detailing Department of Transportation pipeline regulations; detailing requirements for monitoring, reporting, and verification plans; detailing injection well requirements under the Safe Drinking Water Act; and detailing how existing regulations prevent, monitor, and address potential leakage); 75 FR 54970, 55022–23 (Sept. 9, 2010) (disposal of wastewater and solid waste from CAA section 111 standard for Portland cement plants); 54 FR 34008, 34015 (Aug. 17, 1989) (waste disposal impacts of standard of performance for sulfur oxide emissions for fluid catalytic cracking unit regenerators).

[223] *See* 80 FR 64549, 64555 (describing CCS and comparing CCS pollutant disposition to particulate or wet scrubber pollutant disposition).

[224] Pub. L. 95–95, section 109(c)(1)(A) (Aug. 7, 1977), 91 Stat. 699–700.

[225] H.R. Rep. No. 95–294 at 190 (May 12, 1977).

[226] *Id.*

resulting from disposal of the [scrubber system's] liquid purge byproduct.'' [227] That the ACE Rule's interpretation that CAA section 111 limits the BSER to at-the-source measures may be inconsistent with the EPA's prior determinations that traditional control measures like clean fuels and add-on controls qualified as the BSER provides another reason to reject that interpretation.

It should be noted that many of the reasons noted above are comparable to the reasoning by the D.C. Circuit to support its decision in *ALA* that the ACE Rule was incorrect in interpreting CAA section 111 to restrict the BSER to at-the-source measures.[228] The EPA agrees with the D.C. Circuit's reasoning.

In *West Virginia,* the Supreme Court held that the CPP's generation-shifting BSER violated the major question doctrine, and the Court vacated *ALA* on the basis of that holding.[229] However, the Court declined to address the ACE Rule's interpretation of CAA section 111.[230] Thus, its opinion does not cast doubt on the EPA's reasons for rejecting the ACE Rule's interpretation, as noted above and in *ALA.* Several commenters argued that *West Virginia* indicates that control measures that the commenters considered comparable to the generation-shifting BSER of the CPP, including trading programs and other measures that controlled designated facilities in the aggregate, were also precluded from inclusion as the BSER under the major question doctrine.[231] Other commenters disagreed, arguing that *West Virginia* identifies distinctions among those programs, so that the major question doctrine would not necessarily apply.[232] However, as noted in the proposal, in this action, the EPA is not addressing what types of controls, in addition to the generation-shifting BSER of the CPP, would be precluded under CAA section 111 by the major question doctrine. Instead, the EPA will evaluate particular controls against the doctrine, as appropriate, when the EPA considers those controls in future rulemakings under CAA section 111.

2. Minor Amendments or Clarifications

The EPA proposed to amend the regulatory text in subpart Ba to address several editorial and other minor clarifications and is finalizing the amendments as described below. Except as noted specifically below, commenters supported these revisions to the regulatory text.

a. The EPA is finalizing amendments to the applicability provision for subpart Ba under 40 CFR 60.20a, with slight revision from as proposed. As discussed in section II.B. of this preamble, the revised applicability provision clarifies that the provisions of subpart Ba are applicable to an EG published after July 8, 2019. The EPA is finalizing the proposed removal of text that included ''if implementation of such final guideline is ongoing'' because there are no EGs the implementation of which is ongoing; [233] thus, leaving this language in the regulation would be needlessly confusing. Emission guidelines issued on and prior to July 8, 2019, and pursuant to CAA section 129 are subject to the provisions of subpart B. Also, in response to comment that the term ''final emission guideline'' is unclear, the EPA is adding the term ''in the **Federal Register**'' to 40 CFR 60.20a(a) to clarify the publication in the **Federal Register** determines the applicability date. Further clarification of the term ''final emission guideline'' is available in 40 CFR 60.22a(a). A commenter also noted that the proposed rule text deleted all references to ''subpart C of this part'' and removing this language means that it would apply to all EGs in 40 CFR part 60 (that are published after July 8, 2019), including those for incinerators addressed by CAA section 129. This was not the EPA's intent. Therefore, as noted in section III.G.2.b. of this preamble, the EPA is amending the definition of EG within subpart Ba to clarify that subpart Ba does not apply to EGs promulgated under CAA section 129.

b. The EPA is finalizing revisions to 40 CFR 60.21a(e), 60.22a(c), and 60.24a(c) and (f)(1) and (2), largely as proposed, at 40 CFR 60.21a(e), 60.22a(c), and 60.24a(c) and (i)(1) and (2) respectively (differences in numbering are due to provisions changing location in the final regulations relative to proposal). These revisions delete ''subpart C'' from these provisions because EGs can be codified in other subparts of this part and not only in subpart C of this part. In response to a comment requesting clarification, 40 CFR 60.21a(e) is also amended clarify that the definition of emission guidelines for purposes of subpart Ba excludes guidelines promulgated pursuant to CAA section 129. As discussed above, EGs under CAA section 129 are subject to the provisions of subpart B.

c. The EPA is finalizing as proposed an editorial amendment to 40 CFR part 60, subpart A, at § 60.1(a) to add a reference to subpart Ba. The applicability provision in 40 CFR 60.1(a) states that ''[e]xcept as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.'' We are amending this provision to include reference to subpart Ba in addition to subparts B and C.

d. A minor editorial correction at 40 CFR 60.22a(b)(3) amends the term ''nonair quality health environmental effects'' to ''nonair quality health and environmental effects''.

3. Submission of Emissions Data and Related Information

The EPA is finalizing as proposed amendments to 40 CFR 60.25a(a) that delete reference to 40 CFR part 60, appendix D, because the system specified for information submittal by the appendix is no longer in use and clarify that the applicable EG will specify the system for submission of the inventory of designated facilities, including emission data for the designated pollutants and any additional required information related to emissions. The EPA also proposed to delete the term ''related to emissions'' in 40 CFR 60.25a(a). A commenter noted as proposed this deletion caused the provision to be too vague. The EPA agrees that the term ''related to emissions'' should be retained to maintain the original and proper context of this provision. The term is retained by this final action.

4. State Permit and Enforcement Authority

Questions have previously arisen as to whether states may establish standards of performance and other plan requirements as part of state permits

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[227] *Id. See Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 385 n.42 (D.C. Cir. 1973) (''The standard of the ''best system'' is comprehensive, and we cannot imagine that Congress intended that 'best' could apply to a system which did more damage to water than it prevented to air.'').

[228] 985 F.3d 914, 955–41 (D.C. Cir. 2021).

[229] 142 S.Ct. at 2610, 2614, 2615–16.

[230] *Id.* at 2615–16.

[231] API Comment Letter on ''Adoption and Submittal of State Plans for Designated Facilities; Implementing Regulations Under Clean Air Act Section 111(d)'' (''Subpart Ba''), EPA–HQ–OAR–2021–0527–0074 at 8; Lignite Energy Council Comment Letter on Subpart Ba, EPA–HQ–OAR–2021–0527–0100 at 8–9.

[232] Energy Strategy Coalition Comment Letter on Subpart Ba, EPA–HQ–OAR–2021–0527–0088 at 6 (noting that *West Virginia* distinguished the trading program in the Clean Air Mercury Rule, which was based on technological controls, from the trading program in the CPP).

[233] The Municipal Solid Waste Landfills EG, which is currently being implemented, has its own applicability provisions and is subject to subpart B.

and administrative orders. The EPA is confirming with this final action that subpart Ba allows for standards of performance and other state plan requirements to be established as part of state permits and administrative orders, which then must be incorporated into the state plan. See 40 CFR 60.27a(g)(2)(ii).

However, the EPA notes that the permit or administrative order alone may not be sufficient to meet the requirements of an EG or the implementing regulations, including the completeness criteria under 40 CFR 60.27a(g). For instance, a plan submittal must include supporting material demonstrating the state's legal authority to implement and enforce each component of its plan, including the standards of performance, 40 CFR 60.27a(g)(2)(iii), as well as a demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable. *Id.* at § 60.27a(a)(2)(vi). In addition, the specific EGs may also require demonstrations that may not be satisfied by terms of a permit or administrative order. To the extent that these and other requirements are not met by the terms of the incorporated permits and administrative orders, states will need to include materials in a state plan submission demonstrating how the plan meets those requirements. If a state does choose to use permits or administrative orders to establish standards of performance, it needs to demonstrate that it has the legal authority to do so. These implementing regulations do not themselves provide any independent or additional authority to issue permits and administrative orders under states' EPA approved title I and title V permitting programs.

IV. Summary of Cost, Environmental, and Economic Impacts

In amending general implementing regulations, this final action does not independently impose any requirements and therefore does not directly incur any costs or benefits. However, the amendments finalized in this action can impact the costs and benefits of future EGs subject to subpart Ba. The potential impacts of these amendments as reflected in an EG will vary greatly depending on the source category, number and location of designated facilities, and the designated pollutant and potential controls addressed by the EG. Of note, the EPA may propose to supersede these general provisions in an EG as needed and with appropriate justification. Individual EGs are subject to notice and comment rulemaking, providing the opportunity for stakeholders, including the public, to consider the impacts of implementing or superseding these general implementing regulations in the course of those rulemaking actions.

As described in detail in section III.A. of this preamble, the EPA is finalizing amendments to subpart Ba to replace timelines vacated by the D.C. Circuit in *ALA*[234] and to improve and update other provisions within subpart Ba. This section considers general impacts that could result from the amendments finalized in this action as adopted by an EG.

As discussed in section III.A. of this preamble, the EPA does not interpret the D.C. Circuit's direction to require the Agency to quantitatively evaluate the impacts of potential subpart Ba framework timelines, but rather to consider the balance between the public health and welfare benefits resulting from appropriate and reasonable deadlines for the implementation of EGs and the time needed for the technical, administrative, and legislative actions needed to develop and adopt approvable state or Federal plans. The EPA expects that the amendments to subpart Ba finalized in this action will improve the implementation of EGs under CAA section 111(d). In particular, the EPA expects that the timelines finalized both appropriately accommodate state and EPA processes to develop and evaluate plans to effectuate an EG and are consistent with the objective of CAA section 111(d) to ensure that designated facilities expeditiously control emissions of pollutants that the EPA has determined may be reasonably anticipated to endanger public health or welfare.

While the EPA initially proposed a 15-month deadline for state plan submissions following the promulgation of an EG (87 FR 79176, Dec. 23, 2022), most commenters, including states and state organizations, indicated that 15 months could not accommodate the technical, administrative, and legal steps necessary to develop and adopt an approvable state plan. Based on the comments and additional information received, the EPA is finalizing 18 months for state plan submissions after promulgation of a final EG, and finds that the additional time, compared with the 9 months provided in subpart B, will better accommodate states' processes to develop and adopt approvable plans and will most efficiently effectuate the applicable EG. Under an 18-month state plan submission timeframe, the costs of developing a state plan under an applicable EG subject to subpart Ba, compared with the 9 months provided by subpart B, may be spread over 9 additional months. With this state plan submittal timeline, the EPA is providing states sufficient time to develop approvable implementation plans for their designated facilities that adequately address public health and environmental objectives. A timeline that is insufficient for states to conduct, *inter alia,* the appropriate technical analysis and public engagement may preclude them from timely adopting and submitting approvable state plans, which could ultimately delay the implementation of emission reductions. In addition, a successful submittal of approvable state plans will avoid an attendant expenditure of Federal resources associated with the development of a Federal plan.

After receiving a state plan, the EPA first must determine if the plan is complete. The EPA is finalizing amendments to its determination of completeness so the timeframe for such determination is streamlined from six months to 60 days from receipt of the state plan submission (see section III.A.2. of this preamble). If the EPA determines a state plan submission is complete, it then evaluates the plan to determine whether it satisfies the applicable requirements. The Agency proposes an action (*e.g.,* plan approval or plan disapproval) and then finalizes its action pursuant to a notice-and-comment rulemaking process. As described in detail in sections III.A.3. and III.A.4. of this preamble, the EPA is finalizing a 12-month period for the EPA to take final action on a state plan after a submission is found to be complete. The EPA is also finalizing a 12-month timeline for the EPA to promulgate a Federal plan, which runs from either the state plan deadline if a state has failed to submit a state plan, 60 days following the state plan deadline if a state has submitted a plan by the deadline and the EPA determines it is incomplete, or from the date the EPA finalizes disapproval of a state plan submission. As described in detail in section III. of this preamble, because these timeframes provide for the minimum time reasonably necessary for the EPA to accomplish propose and finalize a Federal plan, the EPA expects these timeframes will minimize the impacts on public health and welfare to the extent possible while ensuring that an EG is expeditiously implemented.

As described in detail in section III.A.5. of this preamble, the EPA is finalizing a requirement that state plans include IoPs if the plan requires final

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[234] *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914, 991 (D.C. Cir. 2021).

compliance with standards of performance later than 20 months after the plan submission deadline. The compliance schedule, as defined in subpart Ba (40 CFR 60.21a(g)) is a legally enforceable schedule specifying a date or dates by which a source or category of sources must comply with specific standards of performance contained in a plan. If final compliance for a source to meet their standards of performance is more than 20 months after the state plan submittal deadline, the plan must include IoPs, which are defined steps to achieve compliance (*e.g.,* submittal of a control plan, awarding of contracts for emission control systems or process modification, etc.). This 20 month timeline is the trigger for when IoPs must be included in a state plan. An EG will specify what the IoPs are and associated compliance schedules. The EPA considers this slightly longer timeline than is required under subpart B reasonable given that the EPA is also, in this action, extending the timelines for state plan submission under subpart Ba. The EPA notes that IoPs do not, on their own, govern how expeditiously emission reductions are achieved: this is dictated by the final compliance date, which is established in an individual EG. Additionally, any specific requirements associated with IoPs, including extended or truncated timelines, would be included in the EG, as these are dependent on the source type, pollutant, and control strategy addressed.

The EPA is also finalizing amending subpart Ba to enhance requirements for reasonable notice and opportunity for public participation. In particular, the EPA is requiring that states, as part of the state plan development or revision process, provide documentation that they have conducted meaningful engagement with a broad range of pertinent stakeholders and/or their representatives. Pertinent stakeholders include communities most affected by and vulnerable to the impacts of the plan or plan revision (see section III.C. of this preamble).

Overall, the EPA expects the amendments being finalized in this action will benefit the states in the development of approvable state plans. The EPA expects that the amendments associated with meaningful engagement with pertinent stakeholders will potentially increase the amount of information the states can use in designing state plans, which may increase both the level of resources states will need to employ in the development of an approvable plan, as well as the resulting health and welfare benefits of the plan. In addition to health and welfare benefits, there are also administrative benefits of engaging with stakeholders and receiving pertinent information as a state plan is being developed. Such engagement may improve the record for the state's plan and reduce the amount of comments received when the state plan is proposed to the public, which would reduce the amount of effort employed after proposal to address issues raised by the public and stakeholders.

There is variation and uncertainty in determining the magnitude of impacts, both to states and the public, resulting from amendments associated with meaningful engagement. First, the EPA notes that the meaningful engagement provisions being finalized in this action are largely procedural in nature and do not prescribe any particular set of actions or activities that states must undertake. The potential costs and benefits will therefore be determined in significant part by choices that are within states' discretion. Second, the impacts of conducting meaningful engagement will be highly dependent on the number and location of designated facilities addressed by an EG, as well as on the type of health or environmental impacts of the associated emissions. If stakeholder and public involvement pursuant to the meaningful engagement provisions does not generate a large number of specific and unique comments, data, or other considerations, then the level of effort states will employ to review them will be lower in comparison to when meaningful engagement comments are voluminous. It might also be expected that less input and fewer comments might, in certain cases, have an adverse impact on the ability of a state plan to fulfill its health and welfare objectives.

To the extent that states already conduct significant engagement with pertinent stakeholders, the meaningful engagement amendments will most likely not result in additional costs. Conversely, states that do not have engagement procedures already in place may be required to increase their level of effort to engage with pertinent stakeholders. The burden and benefits of meaningful engagement for the pertinent stakeholders will also be highly dependent on the EG and associated variables such as, but not limited to, the geographical distribution of the facilities and communities impacted, available modes of participation for those areas, the pollutants addressed, and the range of options available to the state and facilities for meeting the EG standards. The burden and benefits to pertinent stakeholders may be difficult to quantify, but overall their engagement will be voluntary and is anticipated to result in feedback that may improve the resulting health and welfare benefits of the state plan as perceived and experienced, particularly by those in communities most affected by and vulnerable to the impacts of the plan.

The EPA is also finalizing revisions to the RULOF provisions in subpart Ba. The amendments included in this final action are intended to provide clarity for states to ensure that less-stringent standards of performance for particular designated facilities are consistent with the statutory requirements, as well as a consistent framework for EPA to evaluate such standards across EGs and states (see section III.E. of this preamble).

The magnitude of impacts, both to states and the public, resulting from the final RULOF amendments will vary depending on the particular EG to which the final provisions would apply. As explained in section III.E.2. of this preamble, the EPA believes Congress intended RULOF as a mechanism for states to apply a less-stringent standard of performance in the unusual circumstances in which the degree of emission limitation determined by the EPA is not reasonable for a particular designated facility. Additionally, states are not required to invoke the RULOF provision in any particular instance and may choose not to do so, even if a particular designated facility's circumstances meet the threshold specified in the regulations. If a state does not invoke RULOF in their state plan, then the amendments will not result in any additional costs. If a state does invoke RULOF in their state plan, then the amendments could, in certain circumstances, result in an increased level of effort to develop standards of performance for certain sources. As such, the RULOF amendments could potentially increase the level of resources states will need to employ in the development of an approvable plan. However, because the amendments clarify is required in order for a less-stringent standard pursuant to RULOF to satisfy the statutory requirements, the amendments reduce the uncertainty of states and designated facilities in the development of such standards. This in turn could result in a decrease in the amount of time that a state that wished to invoke RULOF would need, relative to a situation where the requirements were less defined, by avoiding significant back and forth with the EPA and the sources in the state during state plan development. Overall, the EPA expects the RULOF amendments will benefit the states in the development of approvable state plans and therefore result in benefits to public health and welfare.

Finally, the EPA expects that the requirements for electronic submittal and that the availability of the optional regulatory mechanisms being finalized in this action will improve flexibility and efficiency in the call for and submission, review, approval, and implementation of state plans, and thus will overall result in benefits to the states, the EPA, designated facilities, and public health and welfare. In addition, the EPA expects the requirements for electronic submittal will increase the ease and efficiency of data submittal and data accessibility and benefit the states and the EPA. Electronic submittal will also improve the Agency's efficiency and effectiveness in the receipt and review of state plans.

The EPA expects that the overall impacts of the implementation of the amendments to subpart Ba finalized in this action will improve the implementation of EGs under CAA section 111(d).

V. Statutory and Executive Order Reviews

Additional information about these Statutory and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review; Executive Order 13563: Improving Regulation and Regulatory Review; and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action'' as defined in Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the Paperwork Reduction Act. The requirements in subpart Ba do not themselves require any reporting and recordkeeping activities, and no Information Collection Request (ICR) was submitted in connection with the original promulgation of subpart Ba or the amendments we are finalizing at this time. Any recordkeeping and reporting requirements are imposed only through the incorporation of specific elements of subpart Ba in the individual emission guidelines, which have their own ICRs.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any requirements on small entities. Specifically, this action addresses processes related to state plans for implementation of EGs established under CAA section 111(d).

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This final action does not contain a Federal mandate that may result in expenditures of $100 million or more for state, local, and Tribal governments, in the aggregate or the private sector in any 1 year.

This final action is also not subject to the requirements of section 203 of UMRA because, as described in 2 U.S.C. 1531–38, it contains no regulatory requirements that might significantly or uniquely affect small governments. This action imposes no enforceable duty on any local, or Tribal governments or the private sector. However, this action imposes enforceable duties on states. This action does not meaningfully require additional mandates on states beyond what is already required of them and will not impose a burden in excess of $100 million.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government. The EPA believes, however, that this action may be of significant interest to state governments.

Subpart Ba requirements apply to states in the development and submittal of state plans pursuant to emission guidelines promulgated under CAA section 111(d) after July 8, 2019, to the extent that an EG does not supersede the requirements of subpart Ba. This action finalizes amendments to certain requirements for development, submission, and approval processes of state plans under CAA section 111(d). In particular, the amendments associated with state plan submission deadlines, RULOF provisions, meaningful engagement, and regulatory mechanisms may be of significant interest to state governments. In section IV of this preamble, the EPA summarizes the potential cost, environmental, and economic impacts of the implementation (through individual emission guidelines) of the amendments to subpart Ba being finalized in this action. Overall, the EPA expects these amendments will benefit the states in the development of approvable state plans.

The EPA notes that notice and comment procedures required for the promulgation of individual EGs will provide opportunity for states to address issues related to federalism based on specific application of subpart Ba requirements to that particular EG.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications as specified in Executive Order 13175. It would not impose substantial direct compliance costs on Tribal governments that have designated facilities located in their area of Indian country. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for designated facilities. A tribe with an approved TAS under TAR for CAA 111(d) is not required to resubmit TAS approval to implement an EG subject to subpart Ba. This action also will not have substantial direct costs or impacts on the relationship between the Federal Government and Indian tribes or on the distribution of power and responsibilities between the Federal Government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to the action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it will not have a significant adverse effect on the supply, distribution or use of energy. Specifically, this action addresses the submission and adoption of state plans for implementation of EGs established under CAA section 111(d).

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or indigenous peoples) and low-income populations.

The EPA believes that it is not practicable to assess whether the human health or environmental conditions that exist prior to this action result in disproportionate and adverse effects on people of color, low-income populations and/or indigenous peoples. The 40 CFR part 60, subpart Ba, provisions are the implementing regulations for states to plan in response to individual EGs, and these individual EGs are applicable to specific pollutants from specified categories of existing sources. It is not possible to identify or assess human health and environmental conditions that will be impacted by this rule because this rule does not address a particular set of sources or a particular pollutant. This action is revising the implementing regulations and does not directly impact environmental justice communities or result in new disproportionate and adverse effects.

The EPA identified and addressed environmental justice concerns by specifying new requirements for meaningful engagement with pertinent stakeholders, which includes communities most affected by and/or vulnerable to the impacts of a state plan.

The information supporting this Executive order review is contained in section III.C. and section III.E.3.f. of this action.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Michael S. Regan,
Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 2. Amend § 60.1 by revising paragraph (a) to read as follows:

§ 60.1 Applicability.

(a) Except as provided in subparts B, Ba, and C of this part, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

* * * * *

■ 3. Amend § 60.20a by revising paragraph (a) introductory text to read as follows:

§ 60.20a Applicability.

(a) The provisions of this subpart apply upon publication of a final emission guideline under § 60.22a(a) if the guideline is published in the **Federal Register** after July 8, 2019.

* * * * *

■ 4. Amend § 60.21a by:
■ a. Revising paragraphs (e) and (f); and
■ b. Adding paragraphs (k) and (l).

The revisions and additions read as follows:

§ 60.21a Definitions.

* * * * *

(e) *Emission guideline* means a guideline set forth in this part, with the exception of guidelines set forth pursuant to section 129 of the Clean Air Act, or in a final guideline document published under § 60.22a(a), which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator has determined has been adequately demonstrated for designated facilities.

(f) *Standard of performance* means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated, including a legally enforceable regulation setting forth an allowable rate, quantity, or concentration of emissions into the atmosphere, or prescribing a design, equipment, work practice, or operational standard, or combination thereof.

* * * * *

(k) *Meaningful engagement* means the timely engagement with pertinent stakeholders and/or their representatives in the plan development or plan revision process. Such engagement should not be disproportionate in favor of certain stakeholders and should be informed by available best practices.

(l) *Pertinent stakeholders* include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision.

■ 5. Amend § 60.22a by revising paragraphs (b)(3) and (c) to read as follows:

§ 60.22a Publication of emission guidelines.

* * * * *

(b) * * *

(3) Information on the degree of emission limitation which is achievable with each system, together with information on the costs, nonair quality health and environmental effects, and energy requirements of applying each system to designated facilities.

* * * * *

(c) The emission guidelines and compliance times referred to in paragraph (b)(5) of this section will be proposed for comment upon publication of the draft guideline document, and after consideration of comments will be promulgated in this part with such modifications as may be appropriate.

■ 6. Amend § 60.23a by:
■ a. Revising paragraph (a)(1);
■ b. Adding paragraph (a)(3);
■ c. Revising paragraph (b); and
■ d. Adding paragraph (i).

The revisions and additions read as follows:

§ 60.23a Adoption and submittal of State plans; public hearings.

(a)(1) Unless otherwise specified in the applicable subpart in this part, within eighteen months after publication in the **Federal Register** of a final emission guideline under § 60.22a(a), each State shall adopt and submit to the Administrator a plan for the control of the designated pollutant to which the emission guideline applies. The submission of such plan shall be made in electronic format according to paragraph (a)(3) of this section or as specified in an applicable emission guideline.

* * * * *

(3) States must submit to the Administrator any plan or plan revision using the State Planning Electronic Collaboration System (SPeCS), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*) or through an analogous electronic reporting tool provided by the EPA for the submission of any plan required by this subpart. Do not use SPeCS to submit confidential business information (CBI). Anything submitted using SPeCS cannot later be claimed to be CBI. The State must confer with the Regional Office for the procedures to submit CBI information. All CBI must be clearly marked as CBI.

(b) If no designated facility is located within a State, the State shall submit a letter of certification to that effect to the Administrator within the time specified in paragraph (a) of this section. Such certification shall exempt the State from the requirements of this subpart for that designated pollutant. The State must submit the letter using the SPeCS, or through an analogous electronic reporting tool provided by the EPA for the submission of any plan required by this subpart.

* * * * *

(i) The State must submit, with the plan or revision, documentation of meaningful engagement including a list of identified pertinent stakeholders and/or their representatives, a summary of the engagement conducted, a summary of stakeholder input received, and a description of how stakeholder input was considered in the development of the plan or plan revisions.

■ 7. Amend § 60.24a by:

■ a. Revising paragraphs (b) introductory text, (c), (d), (e), and (f); and

■ b. Adding paragraphs (g), (h), and (i).

The revisions and additions read as follows:

§ 60.24a Standards of performance and compliance schedules.

* * * * *

(b) Standards of performance shall be in the form of an allowable rate, quantity, or concentration of emissions, except when it is not feasible to prescribe or enforce such a standard of performance. The EPA shall identify such cases in the emission guidelines issued under § 60.22a. Where standards of performance prescribing design, equipment, work practice, or operational standards, or combination thereof are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such standards, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

* * * * *

(c) Except as provided in paragraph (e) of this section, standards of performance shall be no less stringent than the corresponding emission guideline(s) specified in this part, and final compliance shall be required as expeditiously as practicable, but no later than the compliance times specified in an applicable subpart of this part.

(d) Any compliance schedule extending more than twenty months from the date required for submittal of the plan must include legally enforceable increments of progress to achieve compliance for each designated facility or category of facilities. Unless otherwise specified in the applicable emission guideline, increments of progress must include, where practicable, each increment of progress specified in § 60.21a(h) and must include such additional increments of progress as may be necessary to permit close and effective supervision of progress toward final compliance.

(e)(1) The State may apply a standard of performance to a particular designated facility that is less stringent than or has a compliance schedule longer than otherwise required by an applicable emission guideline taking into consideration that facility's remaining useful life and other factors, provided that the State demonstrates with respect to each such facility (or class of such facilities) that the facility cannot reasonably achieve the degree of emission limitation determined by the EPA based on:

(i) Unreasonable cost of control resulting from plant age, location, or basic process design;

(ii) Physical impossibility or technical infeasibility of installing necessary control equipment; or

(iii) Other circumstances specific to the facility.

(2) For the purpose of this paragraph (e), the State must demonstrate that there are fundamental differences between the information specific to a facility (or class of such facilities) and the information EPA considered in determining the degree of emission limitation achievable through application of the best system of emission reduction or the compliance schedule that make achieving such degree of emission limitation or meeting such compliance schedule unreasonable for that facility.

(f) If the State makes the required demonstration in paragraph (e) of this section, the plan may apply a standard of performance that is less stringent than required by an applicable emission guideline.

(1) The standard of performance applied under this paragraph (f) must be no less stringent (or have a compliance schedule no longer) than is necessary to address the fundamental differences identified under paragraph (e) of this section. To the extent necessary to determine a standard of performance satisfying that criteria, the State must evaluate the systems of emission reduction identified in the applicable emission guideline using the factors and evaluation metrics EPA considered in assessing those systems, including technical feasibility, the amount of emission reductions, the cost of achieving such reductions, any nonair quality health and environmental impacts, and energy requirements. The States may also consider, as justified, other factors specific to the facility that were the basis of the demonstration under paragraph (e) as well as other systems of emission reduction in addition to those EPA considered in the applicable emission guideline.

(2) A standard of performance under this paragraph (f) must be in the form as required by the applicable emission guideline.

(g) Where a State applies a standard of performance pursuant to paragraph (f) of this section on the basis of an operating condition(s) within the designated facility's control, such as remaining useful life or restricted capacity, the plan must also include such operating condition(s) as an enforceable requirement. The plan must also include requirements to provide for the implementation and enforcement of the operating condition(s), such as requirements for monitoring, reporting, and recordkeeping.

(h) A less stringent standard of performance must meet all other applicable requirements, including in this subpart and in any applicable emission guideline.

(i) Nothing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing, as part of the plan:

(1) Standards of performance more stringent than emission guidelines specified in this part; or

(2) Compliance schedules requiring final compliance at earlier times than those specified in applicable emission guidelines.

(ii) [Reserved]

■ 8. Amend § 60.25a by revising paragraph (a) to read as follows:

§ 60.25a Emission inventories, source surveillance, reports.

(a) Each plan shall include an inventory of all designated facilities, including emission data for the designated pollutants and any additional information related to emissions as specified in the applicable emission guideline. Such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable standards of performance. As used in this subpart, *correlated* means presented in such a manner as to show the relationship between measured or estimated amounts of emissions and the amounts of such emissions allowable under applicable standards of performance.

* * * * *

■ 9. Amend § 60.27a by:

■ a. Revising paragraph (a);

■ b. Adding paragraphs (b)(1) and (2);

■ c. Revising paragraphs (c), (d), (f) introductory text, and (g)(1);

■ d. Removing the word ''and'' from the end of paragraph (g)(2)(viii);

■ e. Redesignating paragraph (g)(2)(ix) as paragraph (g)(2)(x); and

■ f. Adding new paragraph (g)(2)(ix) and paragraphs (h), (i) and (j).

The revisions and additions read as follows:

§ 60.27a Actions by the Administrator.

(a) The Administrator may, whenever he determines necessary, amend the period for submission of any plan or plan revision or portion thereof.

(b) * * *

(1) *Full and partial approval and disapproval.* In the case of any plan or plan revision on which the Administrator is required to act under this paragraph (b), the Administrator shall approve such plan or plan revision as a whole if it meets all of the applicable requirements of this subpart. If a portion of the plan or plan revision meets all the applicable requirements of this subpart, the Administrator may approve the plan or plan revision in part and disapprove in part. The plan or plan revision shall not be treated as meeting the requirements of this chapter until the Administrator approves the entire plan or revision as complying with the applicable requirements of this subpart.

(2) *Conditional approval.* The Administrator may approve a plan or plan revision based on a commitment of the State to adopt and submit to the Administrator specific enforceable measures by a date certain, but not later than twelve months after the date of conditional approval of the plan or plan revision. Any such conditional approval shall be treated as a disapproval if the State fails to comply with such commitment.

(c) The Administrator will promulgate, through notice-and-comment rulemaking, a Federal plan, or portion thereof, at any time within twelve months after:

(1) The State fails to submit a plan or plan revision within the time prescribed or the State has failed to satisfy the minimum criteria under paragraph (g) of this section as of the time prescribed in paragraph (g)(1) of this section; or

(2) The Administrator disapproves the required State plan or plan revision or any portion thereof, as unsatisfactory because the applicable requirements of this subpart or an applicable emission guideline under this part have not been met.

(d) The Administrator will promulgate a final Federal plan, or portion thereof, as described in paragraph (c) of this section unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal plan.

* * * * *

(f) Prior to promulgation of a Federal plan under paragraph (d) of this section, the Administrator will conduct meaningful engagement with pertinent stakeholders and/or their representatives and provide the opportunity for at least one public hearing in either:

* * * * *

(g) * * *

(1) *General.* Within 60 days of the Administrator's receipt of a State submission, the Administrator shall determine whether the minimum criteria for completeness have been met for a plan submission or revision. Any plan or plan revision that a State submits to the EPA, and that has not been determined by the EPA within 60 days after the Administrator's receipt of a State submission to have failed to meet the minimum criteria, shall on that date be deemed by operation of law to meet such minimum criteria. Where the Administrator determines that a plan submission does not meet the minimum criteria of this paragraph (g), the State will be treated as not having made the submission and the requirements of this section regarding promulgation of a Federal plan shall apply.

(2) * * *

(ix) Documentation of meaningful engagement, including a list of pertinent stakeholders or their representatives, a summary of the engagement conducted, and a summary of stakeholder input received, and a description of how stakeholder input was considered in the development of the plan or plan revisions; and

* * * * *

(h) The requirements of this paragraph (h) apply to parallel processing. A State may submit a plan requesting parallel processing prior to adoption and to completion of public outreach and engagement by the State in order to expedite review and to provide an opportunity for the State to consider EPA comments prior to submission of a final plan for final review and action. Under these circumstances and at the discretion of the EPA, the following exceptions to the completeness criteria under paragraph (g)(2) of this section apply to plans submitted explicitly for parallel processing:

(1) The letter required by paragraph (g)(2)(i) of this section must request that EPA propose approval of the proposed plan by parallel processing;

(2) In lieu of paragraph (g)(2)(ii) of this section, the State must submit a schedule for final adoption or issuance of the plan;

(3) In lieu of paragraph (g)(2)(iv) of this section, the plan must include a copy of the proposed/draft regulation or document, including indication of the proposed changes to be made to the existing approved plan, where applicable;

(4) In lieu of paragraph (g)(2)(ix) of this section, the plan must include documentation of the engagement conducted prior to the parallel processing submittal and of any planned additional meaningful engagement to be conducted prior to adoption of the final plan; and

(5) The requirements of paragraphs (g)(2)(v) through (viii) of this section do not apply to plans submitted for parallel processing. The exceptions granted in the preceding sentence apply only to EPA's determination of proposed action and all requirements of paragraph (g)(2) of this section must be met prior to publication of EPA's final determination of plan approvability.

(i) The requirements of this paragraph (i) apply to calls for plan revisions. Whenever the Administrator finds that the applicable plan is substantially inadequate to meet the requirements of the applicable emission guidelines in this part, to provide for the implementation of the applicable requirements, or to otherwise comply with any applicable requirement of this subpart or the Clean Air Act, the Administrator shall require the State to revise the plan as necessary to correct such inadequacies. The Administrator must notify the State of the inadequacies and such plan revisions shall be submitted to the Administrator within twelve months or as determined by the Administrator. Such findings and notice must be public.

(1) Any finding under this paragraph (i) shall, to the extent the Administrator deems appropriate, subject the State to the requirements of this part to which the State was subject when it developed and submitted the plan for which such finding was made, except that the Administrator may adjust any dates applicable under such requirements as appropriate.

(2) If the Administrator makes this finding on the basis that a State is failing to implement an approved plan, or part of an approved plan, the State may submit a demonstration to the Administrator it is adequately implementing the requirements of the approved State plan in lieu of submitting a plan revision. Such demonstration must be submitted by the deadline established under this paragraph (i).

(j) The requirements of this paragraph (j) apply to error corrections. Whenever the Administrator determines that the Administrator's action approving, disapproving, or promulgating any plan or plan revision (or portion thereof) was in error, the Administrator may in the same manner as the approval, disapproval, or promulgation revise such action as appropriate without requiring any further submission from the State. Such determination and the basis thereof shall be provided to the State and public.

■ 10. Amend § 60.28a by revising paragraph (a) to read as follows:

§ 60.28a Plan revisions by the State.

(a) Any significant revision to a State plan shall be adopted by such State after reasonable notice, public hearing, and meaningful engagement. For plan revisions required in response to a revised emission guideline, such plan revisions shall be submitted to the Administrator within fifteen months, or as determined by the Administrator, after publication in the **Federal Register** of a final revised emission guideline under § 60.22a. All plan revisions must be submitted in accordance with the procedures and requirements applicable to development and submission of the original plan.

* * * * *

■ 11. Amend § 60.29a by revising the introductory text to read as follows:

§ 60.29a Plan revisions by the Administrator.

After notice and opportunity for public hearing in each affected State, and meaningful engagement for any significant revision, the Administrator may revise any provision of an applicable Federal plan if:

* * * * *

[FR Doc. 2023–25269 Filed 11–16–23; 8:45 am]

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Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber@ndchamber.com>
Sent: Wednesday, April 3, 2024 5:01 AM
To: Beehler, Jace
Subject: Workforce Showcase | Looysen & Luck | Hear ya Cluckin'

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

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GNDC Unrolls Full Agenda For Workforce Showcase

The Greater North Dakota Chamber is excited to announce a groundbreaking event designed to showcase the plethora of workforce resources available to North Dakota

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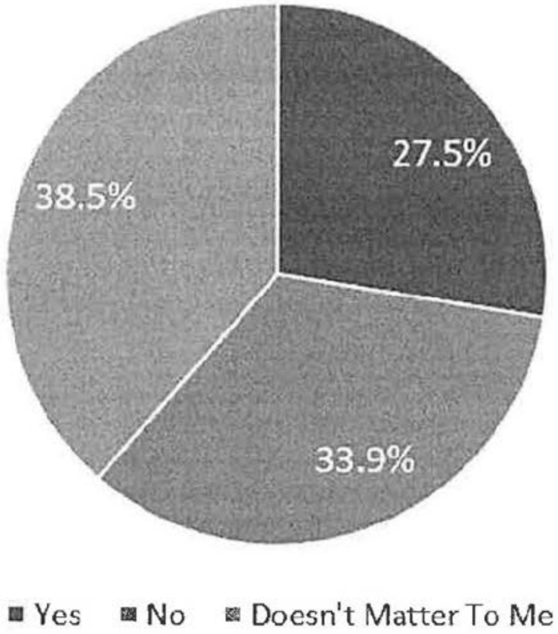

Do you wear your seatbelt regularly?

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FURTHER READING: Some North Dakotans say no to seat belts, study states [KX News]

bek.tv

Both Sides Of The Coin

Key Bridge Collapse

[AP News] A cargo ship lost power and rammed into a major bridge in Baltimore, destroying the span in a matter of seconds and plunging it into the river in a terrifying collapse that could disrupt a vital shipping port for months. ...

A leftist perspective envisions methods to ensure safety standards in the future

We still don't know exactly what mechanical defects caused the Dali to lose power and slam into the Francis Scott Key Bridge. We do know that the ship had prior mishaps... A ship like the Dali is only as good as the inspection regime of the nation where it is registered, which is to say not very good. That is the whole appeal of flags of convenience—to operate ships on the cheap. If the U.S. chose, we

A conservative viewpoint considers constructing the bridge efficiently and within a reasonable timeframe

President Biden may indeed waive some environmental-impact rules in order to speed up the construction of the new Baltimore bridge. But the real question is: Why isn't this done more often with ordinary projects, which now drag on forever?

ALYSSA LOOYSEN
Jamestown/Stutsman County
Development Corp

ALYSSA LOOYSEN has worked in a variety of industries including promotions, hospitality, medical sales, coaching dance team and development work.

In her current role, she assists in planning and directing business recruitment. ... read more.

SANDI LUCK
Bully Brew Coffee House
ND Coffee Roastery

SANDI LUCK has been a serial entrepreneur. She is the founder and owner of several companies in the Midwest (100% woman owned): 8 Bully Brew Coffee Houses, the ND Coffee Roastery, an AIRBNB called Nora's Place, The Board Room Coffee & Taphouse, and she is a real estate investor. ... read more.

Adventures With Liz

Liz Markham, GNDC's Membership Director, is digging into the job! She's got a hunt for adventure and we are just trying to keep up! Ride along!

PREPPING & PARTNERS

On the heels of the State of the Base address, they're prepping for their next big event... 2024 Grand Awards on April 9th. We are excited to be coming to GF in June to have our **ND Future Forum**. Thanks Barry, Kim, Tina, (and Janelle) with **GF/EGF Chamber** for being a great partner!

WANTING TO OPT OUT?

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Greater North Dakota Chamber | PO Box 2639, Bismarck, ND 58502-2639

Unsubscribe jabeehler@nd.gov

Update Profile | Constant Contact Data Notice

Sent by ndchamber@ndchamber.com powered by

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber@ndchamber.com>
Sent: Wednesday, March 20, 2024 5:02 AM
To: Beehler, Jace
Subject: Stressed Out | Neset and Lawrence | Chips and Grilled Cheese

GNDC

GREATER NORTH DAKOTA CHAMBER

DAKOTA DIGEST

Keeping North Dakota Open for Business | **Mar 20**

GNDC SPOTLIGHT

Greater North Dakota Chamber CORNERSTONE MEMBER

ConocoPhillips

Top Of Mind Headline

Fewer Americans say China, Russia top threats to US: Gallup

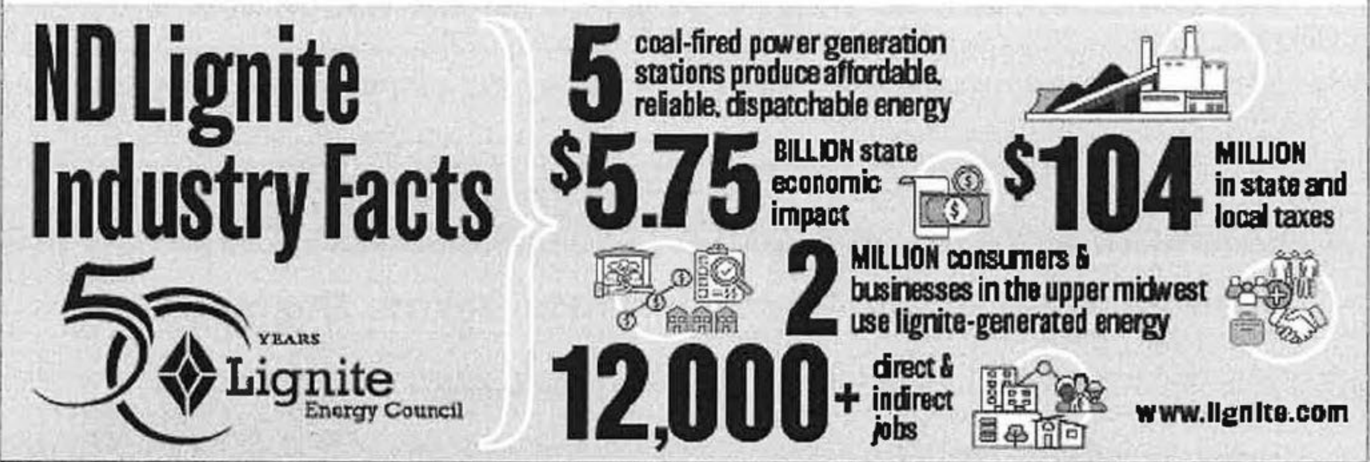
The left is skeptical of the bill, arguing that there is insufficient evidence to justify such a drastic measure.

As Evan Greer, the director at Fight for the Future, a digital rights organization, points out, all social media companies, regardless of where they're based, need to be scrutinized for their capacity to inappropriately surveil Americans and use algorithms to influence American politics. The real solution, people in this camp argue, is not select bans but strict limitations on data that any company can collect on people online. In addition to all this, some civil liberties experts doubt a TikTok ban will survive a First Amendment challenge.
Zeeshan Aleem, MSNBC

The right supports the bill, arguing that TikTok is a propaganda tool for the Chinese government.

Congressional offices were inundated with tens of thousands of phone calls [last] Thursday from panicked young adults who had received a notification from TikTok warning that the app could be shut down... Some users reported that they had to make the call in order to use the app...

This should be a major scandal. A company directly tied to and controlled by the Chinese Communist Party is pushing American children into direct political action. At best, this is political interference by the U.S.'s top adversary. At worst, it's a deliberate effort to weaponize the mental health of American children and divide the country internally — all to force the U.S. government to abandon its national security objectives.
Kaylee McGhee White, Washington Examiner



The Poll

Poll powered by BEK

KATHLEEN NESET
Neset Consulting Service

KATHLEEN NESET is owner and president of NESET which provides engineering and geologic expertise to the oil industry. She received a bachelor's degree in geology from Brown University ... read more.

TIFFANY LAWRENCE
Sanford Health

As president and CEO, **TIFFANY LAWRENCE** oversees the management and operations of Sanford Health Fargo, North Dakota's largest health care provider and employer. With a background in finance ... read more.

UPCOMING GNDC EVENTS

MEMBER EVENT
March 27
ND 12th Annual Expo: Selling to the Government
Bismarck
8 AM – 4 PM

April 9
Policy Outlook: Economic Development Programs
Virtual

GrowND: Workforce Solutions Showcase

April 23 | Bismarck, ND

This new GNDC event is a rapid-fire intro series to current opportunities available to businesses in ND.

The first two hours of this 3-hour event will feature a sequence of concise, 10-minute vignettes to explain available solutions related to workforce challenges. A social will follow to ask questions and engage with speakers and attendees.

Register To Attend

Adventures With Liz

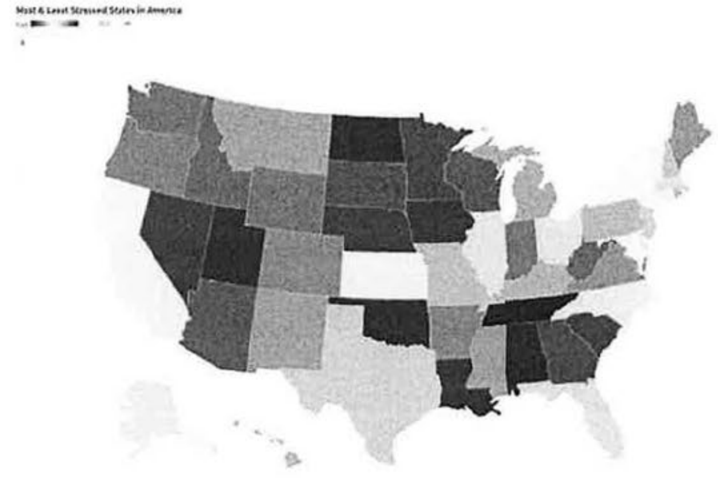
Liz Markham, GNDC's Membership Director, is digging into the job! She's got a hunt for adventure and we are just trying to keep up! Ride along!

COMMON GROUND
When Cory Fong, MDU Resources Group invited Liz to join their table at the Bismarck Mandan Chamber EDC Focus event, Liz jumped at the opportunity. Cory is not only a GNDC Board Member, but also one of the nicest guys you'll meet in ND Business. He brings his passion for policy forward as well as a thoughtfulness and appreciation for GNDC's efforts. Liz appreciated the seat at the table and the conversations that took place.

By The Numbers

Map Shows the Most and Least Stressed US States

The United States is one of the wealthiest countries in the world, and yet, according to recent Gallup polls, it is also one of the most stressed.



More than a quarter of U.S. adults report feeling too stressed to function most days, according to a poll conducted by the American Psychological Association in 2022. However, people in some states are significantly more stressed than others. So which states top the list?

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber@ndchamber.com>
Sent: Thursday, March 14, 2024 5:02 AM
To: Beehler, Jace
Subject: Tax Credit | TikTok | Tuition

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

GNDC

GREATER NORTH DAKOTA CHAMBER DAKOTA DIGEST

Keeping North Dakota Open for Business March 14

GNDC
Greater North Dakota Chamber
CORNERSTONE MEMBER

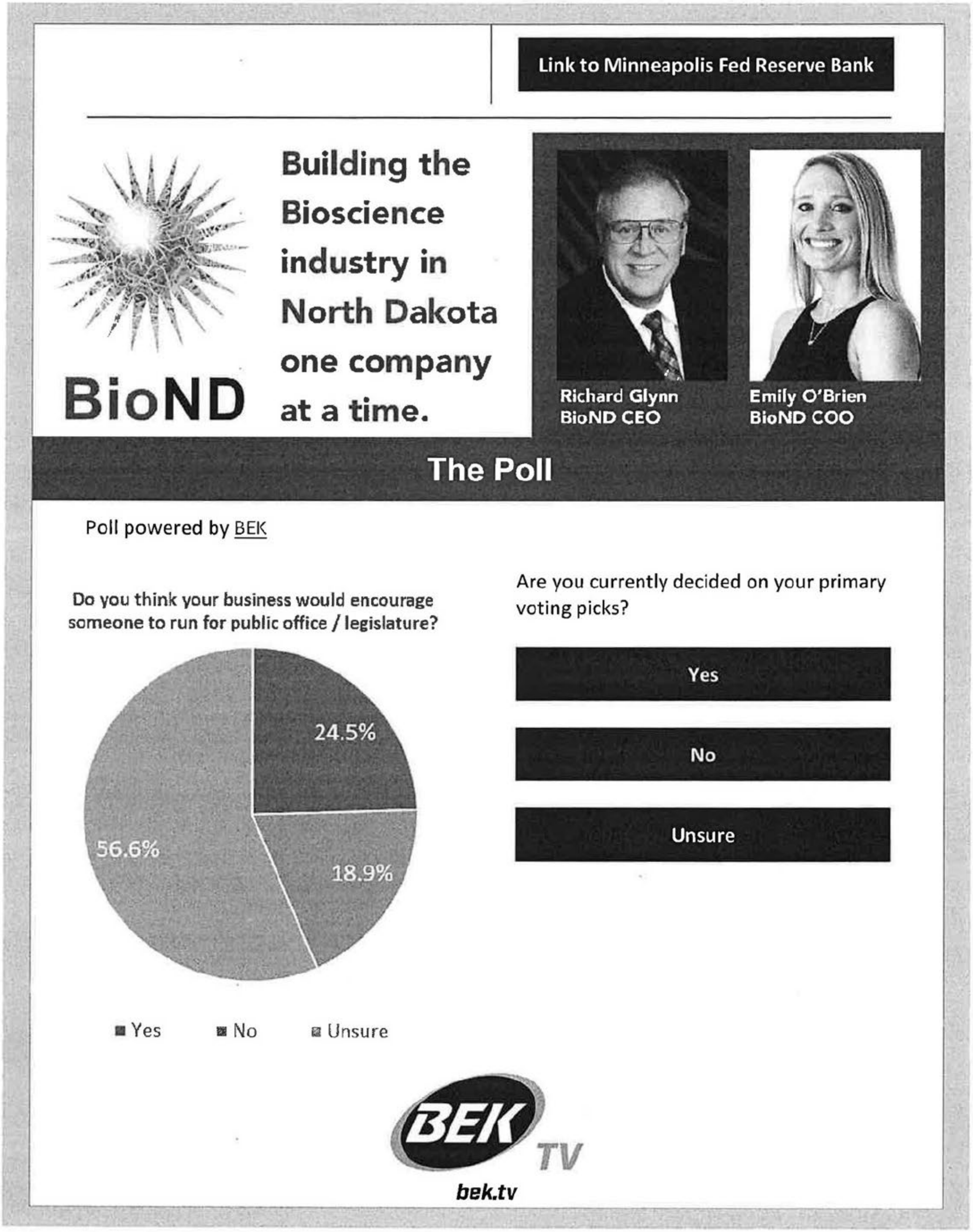
SPOTLIGHT

HESS

Top Of Mind Headline

House passes bill banning TikTok; measure moves to Senate

The House on Wednesday approved a bill that would ban TikTok in the U.S. if Chinese parent company ByteDance doesn't sell the social media app.



Link to Minneapolis Fed Reserve Bank

BioND

Building the Bioscience industry in North Dakota one company at a time.

Richard Glynn
BioND CEO

Emily O'Brien
BioND COO

The Poll

Poll powered by BEK

Do you think your business would encourage someone to run for public office / legislature?

Are you currently decided on your primary voting picks?

Yes

No

Unsure

BEK TV

bek.tv

collaboration. We love this opportunity as we have so many organizational goals that align. ND is open for business! We know that – they know that... this is going to be fun!

UPCOMING GNDC EVENTS

March 19
Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

MEMBER EVENT
March 27
ND 12th Annual Expo: Selling to the Government
Bismarck
8 AM – 4 PM

April 23
GrowND: Workforce Solutions Showcase
Bismarck
1 - 4:30 PM

Policy Outlook: Work Based Learning

March 19 | Virtual

Introducing our innovative monthly Policy Outlooks. These concise 30-45 minute virtual meetings unite subject matter experts, government officials, and businesses to discuss critical topics like business climate, taxes, workforce recruitment, and infrastructure. These sessions will cultivate conversations that shape the future of North Dakota's economy.

Presenter: WAYDE SICK, ND Dept of Career & Tech Ed.

The event will be remote/virtual. To receive call-in information, attendees will need to register in advance.

Register To Attend

Sponsored By: Golden Path Solutions

What Else Are We Reading

Global & National

- Barnes & Noble CEO says retailer is expanding again thanks to Taylor Swift, Legos, and a return to bookselling roots [Fortune]
- The Hot, New High-Paying Career Is An AI Prompt Engineer [Forbes]

North Dakota & Regional

- Counties receiving the most SBA loans in North Dakota [KX News]
- **MEMBER IN THE NEWS:** Public Service Commission approves permits for two transmission lines in northwest North Dakota [KFYR TV]

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber@ndchamber.com>
Sent: Tuesday, March 12, 2024 5:05 AM
To: Beehler, Jace
Subject: Daylight Saving | Gas $$ | Small Business Optimism

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GNDC

GREATER NORTH DAKOTA CHAMBER DAKOTA DIGEST

Keeping North Dakota Open for Business March 12

SPOTLIGHT

GNDC
Greater North Dakota Chamber
CORNERSTONE MEMBER

Essentia Health

Top Of Mind Headline

North Dakota Department of Environmental Quality releases plan for fighting climate change

The Priority Climate Action Plan is meant to reduce greenhouse gas emissions and improve environmental sustainability across the state, including five tactics being implemented now.

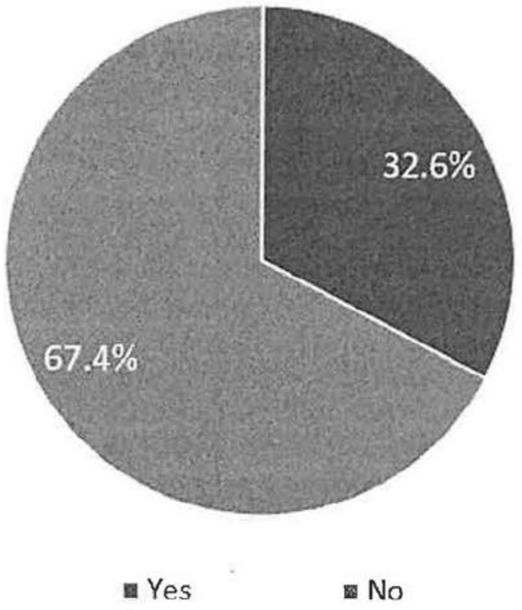
Link to Fox Business

Link to Bismarck Tribune

The Poll

Poll powered by BEK

Have you filed your taxes yet?



Did you watch Biden's State of the Union?

Yes

No

FURTHER READING: Length of State of the Union Addresses in Minutes [The American Presidency Project]

bek.tv

Liz Markham, GNDC's Membership Director, is digging into the job! She's got a hunt for adventure and we are just trying to keep up! Ride along!

IT'S WHAT YOU KNOW AND WHO YOU KNOW
Liz is no dummy... she learned quickly that anytime she can hang out with Jill Berg (Insight Consulting), she should! She recently attended two days of intense training along with some of the team members from General Equipment. Jill made GNDC's 2023 list of Women You Should Know in ND Business... and for good reason.

UPCOMING GNDC EVENTS

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Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

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Register To Attend

Sponsored By: Golden Path Solutions

What Else Are We Reading

Global & National	**North Dakota & Regional**

We will get you taken care of! After all, you still want to be in the know!

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber@ndchamber.com>
Sent: Wednesday, March 6, 2024 5:01 AM
To: Beehler, Jace
Subject: DINKS vs DIPS | OK Unemployment | McConnell

GNDC

GREATER NORTH DAKOTA CHAMBER

DAKOTA DIGEST

Keeping North Dakota Open for Business | **March 6**

GNDC
Greater North Dakota Chamber
CORNERSTONE MEMBER

SPOTLIGHT

ND

Top Of Mind Headline

What recession? Professional forecasters raise expectations for US economy in 2024

The left criticizes McConnell, arguing that he relentlessly pursued partisan goals to the detriment of the country.

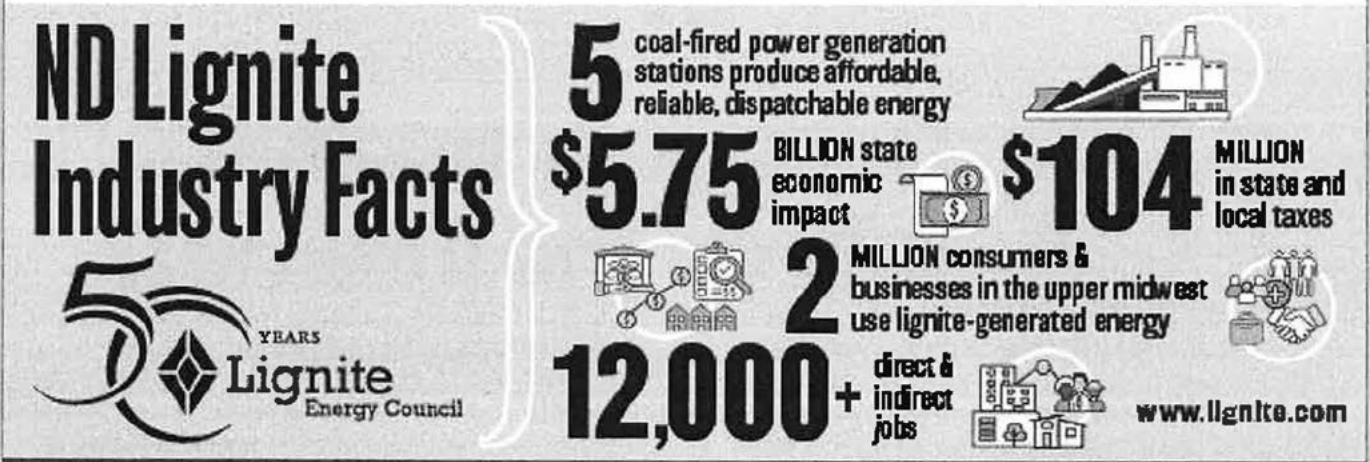
This is the guy who violated every known norm to hold open Justice Antonin Scalia's seat, ostensibly because it came open in an election year, only to fill Justice Ruth Bader Ginsburg's seat when people were already voting in the 2020 election. I think he made a lot of Americans wake up and realize that this was all Calvinball, that he had no principles to begin with...

But even more than that, Mitch McConnell was the guy who realized you don't need to win elections to enact Republican policy. You don't need to change hearts and minds. You don't need to push ballot initiatives or win over the views of the people. All you have to do is stack the courts. You only need 51 votes in the Senate to stack the courts with far-right partisan activists like Aileen Cannon and Matthew Kacsmaryk. And they will enact Republican policies under the guise of judicial review.
Mark Joseph Stern, Slate

The right generally praises McConnell, arguing that he effectively advanced conservative priorities.

Others counter, it is true that McConnell could be too cautious at times, present his caucus with unpalatable last-minute deals, and sometimes back the wrong horse in Senate primaries. But, overall, his judgment was sound, and anyone who thinks Republicans could have accomplished more with a more aggressive leader congenial to the bomb throwers now has the cautionary example of the post–Kevin McCarthy House GOP to consider...

He won the trust of most of his caucus and was always cognizant of their political needs. Even with narrow majorities, he was able to muster an extraordinary degree of party unity and had a knack for knowing when to cut a deal and when to draw a line. At the top of his game, his Democratic counterparts, Harry Reid and then Chuck Schumer, couldn't come close to matching him as a political chess player or legislative tactician; sometimes it didn't even seem fair.
The Editors, National Review



The Poll

Poll powered by BEK

Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

April 23
GrowND: Workforce Solutions Showcase
Bismarck
1 - 4:30 PM

May 7
Women You Need to Know List and Luncheon
Bismarck
11:45 AM - 1 PM

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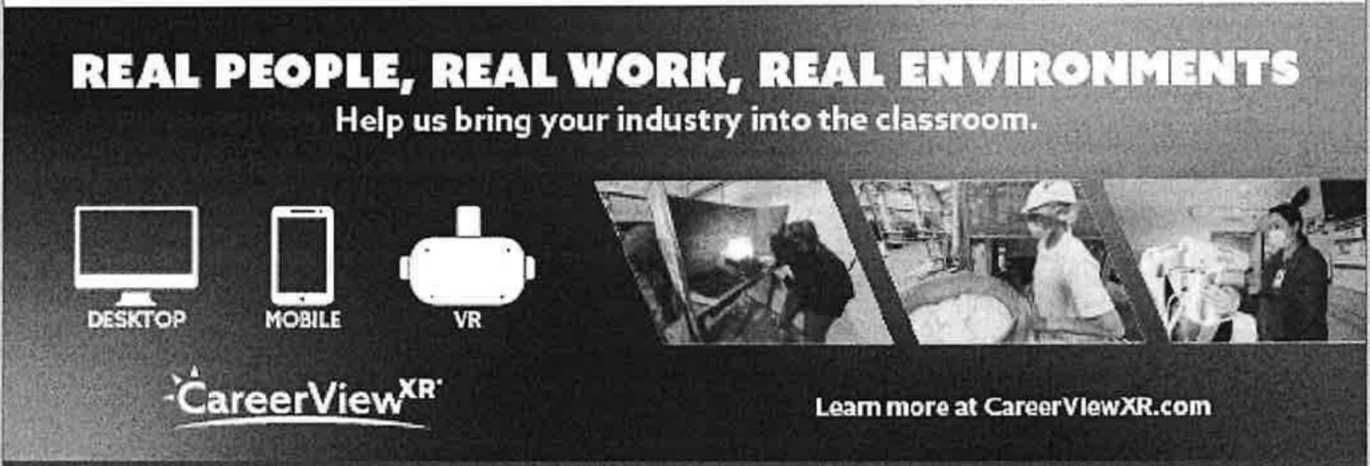
Register To Attend

Event Social Sponsor

CareerView^XR
Career Exploration Experiences by
Be More Colorful



What Else Are We Reading

Global & National

- Meet the DIPS parents: Double Income, Public School. They've got it better than the POLKs, or Parents of Little Kids. [Business Insider]
- It's time to talk about our declining population and its

North Dakota & Regional

- Trump captures North Dakota [Politico]
- What North Dakota's immigrant population looked like in 1900 [KX News]

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Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber@ndchamber.com>
Sent: Tuesday, February 20, 2024 5:00 AM
To: Beehler, Jace
Subject: Knock Out | SD Hunting Rules | Next in Line

GNDC

GREATER NORTH DAKOTA CHAMBER DAKOTA DIGEST

Keeping North Dakota Open for Business **Feb 20**

SPOTLIGHT

GNDC
Greater North Dakota Chamber
CORNERSTONE MEMBER

APEX
CLEAN ENERGY

Top Of Mind Headline

60 Grants, Loans and Programs to Benefit Your Small Business

outlook for deposit rates depends on the policy rate path, deposit levels are likely to remain stable under alternative policy scenarios.

Link to KS Fed

prevent people from fraudulently claiming to be residents in order to obtain resident elk and big horn sheep licenses.

Link to Keloland

The Poll

Poll powered by BEK

RECHECK: Have you applied for the $500 Property Tax Credit?

Yes

No

BEK TV
bek.tv

National & Global

Biden administration will end enrollment in affordable internet program as funding runs low

UPCOMING GNDC EVENTS

March 19
Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

April 9
Policy Outlook: Economic Development
Virtual Meeting
9 AM

April 23
GrowND: Workforce Solutions Showcase
Bismarck
1 - 4:30 PM

Policy Outlook: Work Based Learning

March 19 | Virtual

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Greater North Dakota Chamber | PO Box 2639, Bismarck, ND 58502-2639

From: Greater North Dakota Chamber <ndchamber@ndchamber.com>
Sent: Tuesday, February 13, 2024 5:01 AM
To: Beehler, Jace
Subject: The Dakota Digest: The best morning briefing

GREATER NORTH DAKOTA CHAMBER
DAKOTA DIGEST

Keeping North Dakota Open for Business | **Feb 13**

SPOTLIGHT

GNDC Greater North Dakota Chamber CORNERSTONE MEMBER

ONEOK

Top Of Mind Headline

North Dakota Supreme Court upholds dismissal of Bismarck-Mandan Rail Bridge lawsuit

The Oglala Sioux Tribe in South Dakota has banned Gov. Kristi Noem from the Pine Ridge Reservation, one of the largest in the U.S. This comes days after the Republican governor gave a speech about wanting to send razor wire and security personnel to Texas to help deter immigration at the U.S.-Mexico border.

"Due to the safety of the Oyate, effective immediately, you are hereby Banished from the homelands of the Oglala Sioux Tribe!" Tribe President Frank Star Comes Out said in a Friday statement addressed to Noem. "

Link to USNews

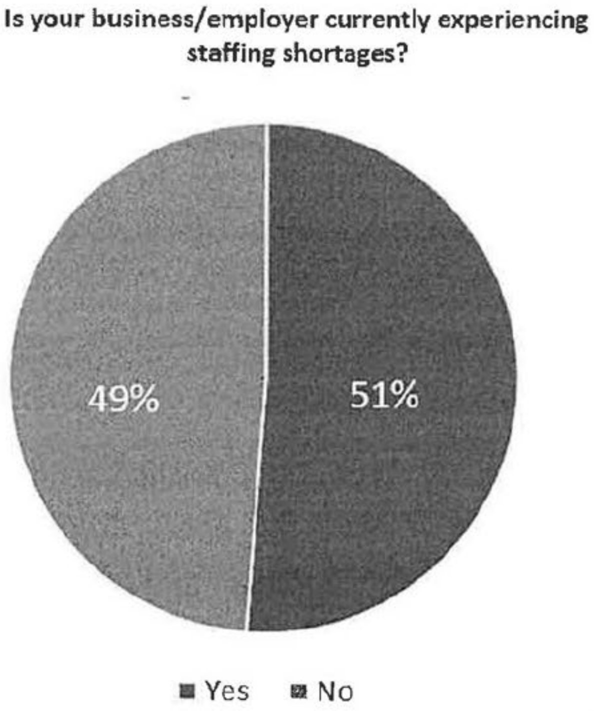
North Dakota would be the first state to set an age limit for U.S. Senate and House candidates under a measure that could go before voters in June, though it's unclear whether a state limit on federal officeholders would violate the U.S. Constitution.

The move comes at a time of heightened interest in the topic given the advanced age of some congressional leaders and the leading presidential candidates in both parties. At least one political observer said the move could be an effort to create a test case for the nation.

Link to AP News

The Poll

Poll powered by BEK



Do you think Social Security benefits should be taxed?

Yes

No

Unsure

FURTHER READING: 41 States That Won't Tax Social Security Benefits in 2024 [MSN]

bek.tv

UPCOMING GNDC EVENTS

February 13- TODAY
Policy Outlook: Tax Policy
Virtual Meeting
9 AM

March 19
Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

April 9
Policy Outlook: Economic Development
Virtual Meeting
9 AM

April 23
GrowND: Workforce Solutions Showcase
Bismarck
1 - 4:30 PM

GrowND: Workforce Solutions Showcase
April 23 | Bismarck, ND

This new GNDC event is a rapid-fire intro series to current opportunities available to business in ND. The first two hours of this 3-hour event will feature a sequence of concise, 10-minute vignettes to explain available solutions related to workforce challenges.

Register To Attend

Confirmed Speakers:

- **Matthew Chaussee**, CEO, CareerViewXR (by Be More Colorful)
- **Patrick Mineer**, CEO/Founder, Golden Path Solutions
- **Katie Ralston Howe**, Workforce Division Director, ND Department of Commerce
- **Jerry Rostad**, Vice Chancellor of Strategy and Strategic Engagement, ND University Systems
- **Damian Schlinger**, Vocational Rehabilitation Director, ND Dept of Health & Human Services
- **Wayde Sick**, ND Department of Career & Technical Education

Event Social Sponsor CareerView XR Career Exploration Experiences by Be More Colorful

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We will get you taken care of! After all, you still want to be in the know!

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber@ndchamber.com>
Sent: Thursday, February 8, 2024 5:00 AM
To: Beehler, Jace
Subject: The Dakota Digest: The best morning briefing

GREATER NORTH DAKOTA CHAMBER
DAKOTA DIGEST

Keeping North Dakota Open for Business | **Feb 8**

GNDC Greater North Dakota Chamber CORNERSTONE MEMBER

SPOTLIGHT

MIDCO

Top Of Mind Headline

Fargo child care center announces 24-hour service, expansion

inflation and the economy — a trend that could sustain consumer spending, fuel economic growth and potentially affect President Joe Biden's political fortunes.

A measure of consumer sentiment by the University of Michigan has jumped in the past two months by the most since 1991. A survey by the Federal Reserve Bank of New York found that Americans' inflation...

Link to Bismarck Tribune

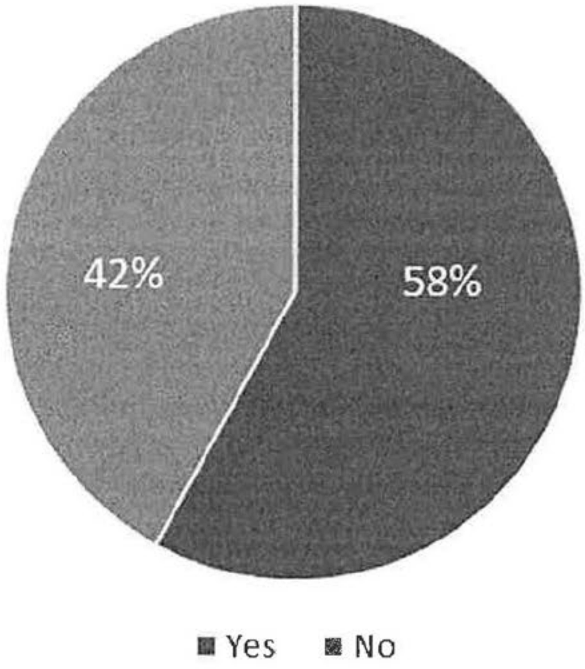
"When the Legacy Fund was established, nobody thought the fund would be approaching $10 billion, so the amount of principal that could be withdrawn in the event of a budgetary emergency was set high, at 15%", said Rep. Glenn Bosch, R-Bismarck, a member of a Legacy Fund advisory committee.

Link to InForum

The Poll

Poll powered by BEK

Have you met (or on track to meet) your New Year's resolutions?



Is your business / employer currently experiencing staffing shortages?

Yes

No

bek.tv

STTAR PROGRAM | Our STEM students want to help solve real challenges.

You can give them that experience.

UPCOMING GNDC EVENTS

February 13
Policy Outlook: Tax Policy
Virtual Meeting
9 AM

March 19
Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

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- **Jerry Rostad,** Vice Chancellor of Strategy and Strategic Engagement, ND University Systems
- **Damian Schlinger**, Vocational Rehabilitation Director, ND Dept of Health & Human Services
- **Wayde Sick**, ND Department of Career & Technical Education

Event Social Sponsor

CareerViewXR
Career Exploration Experiences by
Be More Colorful

Partner Sponsor

NORTH Dakota | Vocational Rehabilitation
Be Legendary. HEALTH & HUMAN SERVICES

What Else Are We Reading

WANTING TO OPT OUT?

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We will get you taken care of! After all, you still want to be in the know!

Lemieux, Kayla M.

From: Arik Spencer
Sent: Thursday, January 18, 2024 6:55 AM
To: Beehler, Jace
Subject: Re: The Dakota Digest: The best morning briefing

No worries!

Sent from my Verizon, Samsung Galaxy smartphone
Get Outlook for Android

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Thursday, January 18, 2024 6:54:13 AM
To: Arik Spencer <arik@ndchamber.com>
Subject: FW: The Dakota Digest: The best morning briefing

Thank you!

From: Greater North Dakota Chamber <ndchamber+ndchamber.com@ccsend.com>
Sent: Thursday, January 18, 2024 5:01 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: The Dakota Digest: The best morning briefing

[redacted]

Regional & Local

Child care gaps in rural America threaten to undercut small communities

Candy Murnion remembers vividly the event that pushed her to open her first day care business in Jordan, a town of fewer than 400 residents in a sea of grassland in eastern Montana.

Garfield County's public health nurse, one of few public health officials serving the town and nearly 5,000 square miles that surround it, had quit because she had given birth to her second child and couldn't find day care.

And she isn't alone.

Data collected prior to the pandemic shows that...

North Dakota Ethics Commission sees uptick in complaints

Complaints to the North Dakota Ethics Commission have been on the rise since late 2022, though the commission says it can't disclose any specifics about them.

In most cases, state law requires filings to be kept confidential unless the commission determines them to be substantiated.

"We understand the irony of that, because we're the Ethics Commission and we're all about transparency," said Executive Director Rebecca Binstock.

Fielding ethics complaints is the...

US Chamber of Commerce calls for more "optimistic" message on economy

The U.S. Chamber of Commerce is making a full-throated defense of free enterprise, launching a counter-offensive against a "constant loop of pessimism" from businesses and politics that is undermining faith in the country's outlook.

Driving the news: CEO Suzanne Clark is expected to insist in a speech on Thursday that the virtues of American capitalism are being drowned out by a news cycle that amplifies "everything [that's] wrong, and bad, and dire about this country."

Link to Axios

[redacted]

Adventures With Liz

Policy Outlook: Work Based Learning

Virtual Meeting

9 AM

April 23

GrowND: Workforce Solutions Showcase

Bismarck

1 - 4:30 PM

- **Wayde Sick**, ND Department of Career & Technical Education

Social Sponsor

What Else Are We Reading

Global & National

- Arizona faces a $1 billion deficit as the state Legislature opens the 2024 session [ABC News]
- Top Risks 2024 [Eurasia]
- Companies are backing away from "DEI" [Axios]

North Dakota & Regional

- Legislation would cut child care costs for Nebraska child care workers [Norfolk News]
- North Dakota Democratic-NPL announces candidates for presidential primary [Bismarck Tribune]

Chamber Champion Of The Week

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber+ndchamber.com@ccsend.com>
Sent: Thursday, January 18, 2024 5:01 AM
To: Beehler, Jace
Subject: The Dakota Digest: The best morning briefing

GNDC

GREATER NORTH DAKOTA CHAMBER

DAKOTA DIGEST

Keeping North Dakota Open for Business | **Jan 17**

Top Of Mind Headline

2024 State of the State Address

and nearly 5,000 square miles that surround it, had quit because she had given birth to her second child and couldn't find day care.

And she isn't alone.
Data collected prior to the pandemic shows that...

Link to Bismarck Tribune

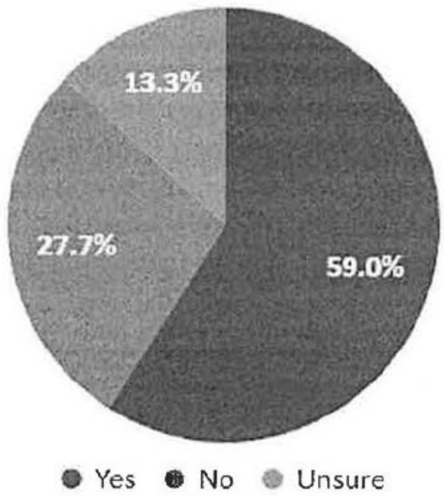
"We understand the irony of that, because we're the Ethics Commission and we're all about transparency," said Executive Director Rebecca Binstock.

Fielding ethics complaints is the...

Link to InForum

The Poll

Poll powered by BEK


Have you ever contributed to a political action committee (PAC)?

If you do not contribute to political action committees (PAC), why haven't you?

No Interest

Can't Afford

Support Candidate(s) Directly

Unaware of Opportunities

Other

bek.tv

National & Global

US Chamber of Commerce calls for more "optimistic" message on economy

UPCOMING GNDC EVENTS

February 13
Policy Outlook: Tax Policy
Virtual Meeting
9 AM

March 19
Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

April 23
GrowND: Workforce Solutions Showcase
Bismarck
1 - 4:30 PM

GrowND: Workforce Solutions Showcase

April 23 | Bismarck, ND

This new GNDC event is a rapid-fire intro series to current opportunities available to business in ND. The first two hours of this 3-hour event will feature a sequence of concise, 10-minute vignettes to explain available solutions related to workforce challenges.

Register To Attend

Confirmed Speakers:

- **Matthew Chaussee**, CEO, CareerViewXR (by Be More Colorful)
- **Katie Ralston Howe**, Workforce Division Director, ND Department of Commerce
- **Wayde Sick**, ND Department of Career & Technical Education

Social Sponsor

CareerView XR
Career Exploration Experiences by
Be More Colorful

What Else Are We Reading

Global & National

- Arizona faces a $1 billion deficit as the state Legislature opens the 2024 session [ABC News]

North Dakota & Regional

- Legislation would cut child care costs for Nebraska child care workers [Norfolk News]

From:	Beehler, Jace
Sent:	Thursday, January 11, 2024 6:49 AM
To:	Nowatzki, Mike G.
Subject:	Re: The Dakota Digest: The best morning briefing

Thank you!!

Get Outlook for iOS

From: Nowatzki, Mike G. <mnowatzki@nd.gov>
Sent: Thursday, January 11, 2024 2:58:09 AM
To: Beehler, Jace <jabeehler@nd.gov>; Hopkins, Danelle <dhopkins@nd.gov>
Subject: RE: The Dakota Digest: The best morning briefing

Yes, we'll get them a write-up.

Thanks,

Mike

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Thursday, January 11, 2024 12:12 AM
To: Nowatzki, Mike G. <mnowatzki@nd.gov>; Hopkins, Danelle <dhopkins@nd.gov>
Subject: RE: The Dakota Digest: The best morning briefing

Hello – Just wanted to check back to see if you both saw this and to see if we can provide something to GNDC?

Thanks!
Jace

From: Beehler, Jace
Sent: Wednesday, January 10, 2024 9:28 AM
To: Nowatzki, Mike G. <mnowatzki@nd.gov>; Hopkins, Danelle <dhopkins@nd.gov>
Subject: FW: The Dakota Digest: The best morning briefing

Can we provide something here?

From: Arik Spencer <arik@ndchamber.com>
Sent: Wednesday, January 10, 2024 9:26 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: RE: The Dakota Digest: The best morning briefing

Hi Jace,

Keeping North Dakota Open for Business **Jan 10**

Top of Mind Headline

Biden administration to unveil contractor rule that could upend gig economy

The administration of U.S. President Joe Biden will release a final rule as soon as this week that will make it more difficult for companies to treat workers as independent contractors rather than employees that typically cost a company more, an administration official said.

The U.S. Department of Labor rule, which was first proposed in 2022 and is likely to face legal challenges, will require that workers be considered employees entitled to more benefits and legal protections than contractors when they are "economically dependent" on a company.

Link to Reuters

presence in the Middle East can only be addressed by reducing that presence...
Concerns that Iran might be emboldened by such moves are overblown. Facing domestic political and economic pressure, Iran has little to gain from starting a regional war, and has instead pursued diplomatic efforts with neighbors in recent months. And its malign meddling across the region, while certainly a concern, is best countered through intelligence cooperation, maritime and air defense partnerships with allies, and targeted sanctions.
Frederic Wehrey and Jennifer Kavanagh, Los Angeles Times

action within the Philippines's exclusive economic zone because it makes grand imperialist claims over the near entirety of the South China Sea...

The Philippines is a treaty defense ally of the U.S. Beijing is ultimately engaged in exactly the same action as the Houthis: attacking the rights of free navigation in international waters. In turn, it should be an absurd proposition for the U.S. to defend Chinese shipping interests.
Tom Rogan, Washington Examiner

[redacted]

Member Poll

Poll powered by BEK

Adventures with Liz

Liz Markham, GNDC's Membership Director, is digging into the job! She's got a hunt for adventure and we are just trying to keep up! Ride along!

COFFEE, COPIES, AND GOOD COMPANY

Lindsey Rath-Wald came over for coffee and extra copies of the latest Report on Business (DEI). We were excited that she supplied content for a column showcasing how First International Bank & Trust is engaging in growing business. Lindsey lit Liz's fire when she talked about small business and start-up stats. As a previous small business owner, Liz understands that business needs supporters and financial institutions are some of the biggest cheerleaders for business... well them and GNDC!

UPCOMING GNDC EVENTS

February 13
Policy Outlook: Tax Policy
Virtual Meeting

Policy Outlook: Tax Policy

Feb 13 | Virtual

To receive call-in information, attendees will need to register in advance.

Register to Attend

The minimum wage is going up in 22 states on Jan. 1

For Americans making minimum wage, it's an automatic raise — but it also ripples out. Typically, increasing the wage floor for the lowest earners pushes up pay for those who make a bit more than the minimum, as employers have to adjust pay scales upwards.

The big picture: More states are requiring a $15 an hour minimum wage — including New York, Maryland, and New Mexico — a dozen years after Fight for $15 kicked off its campaign. Thanks to inflation, the dollar amount doesn't quite mean what it used to.

Link to Axios

WANTING TO OPT OUT?

If you want to unsubscribe from this 3x/week email but still receive all other GNDC communications - reply STOP to this email.
We will get you taken care of! After all, you still want to be in the know!

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber+ndchamber.com@ccsend.com>
Sent: Thursday, January 11, 2024 5:01 AM
To: Beehler, Jace
Subject: The Dakota Digest: The best morning briefing

GNDC

GREATER NORTH DAKOTA CHAMBER DAKOTA DIGEST

Keeping North Dakota Open for Business **Jan 11**

Top of Mind Headline

North Dakota to follow judge's redistricting order for 2024 election, despite appeal

for treating mental or physical illness, going to medical appointment, caring for a family member who's ill, and even due to inclement weather that may close children's school and keep them home.

It also covers absences related domestic abuse or sexual assault.

Anyone is eligible for the sick and safe time if they work 80 hours a year and don't qualify as an independent contractor...

Link to CBS News

That first billion came from conventional wells.

Ness said there's more oil in the Bakken that can be recovered.

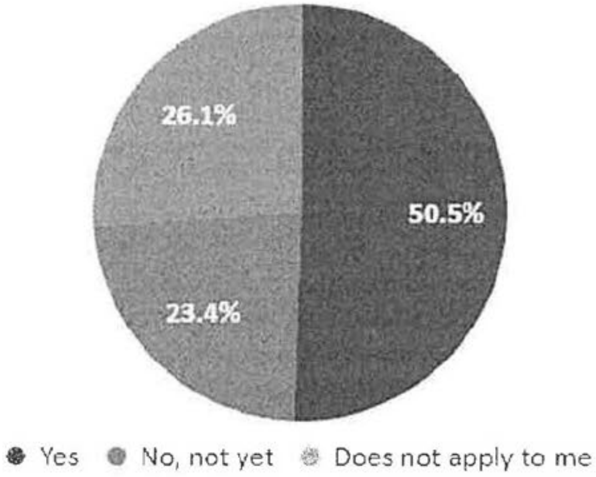
"Somewhere down the line, technology and opportunity are going to align," Ness said. "We have the opportunity to extend the life of the Bakken another 30 to 50 years, and produce another 5 to 8 billion more barrels, just because of technology."

Link to Prairie Public

The Poll

Poll powered by BEK

Have you applied for the $500 Property Tax Credit?



What do you predict will be the top trends/news stories of 2024?

Elections

Select

Geopolitical Volatility

Select

Workforce Issues

Select

Artificial Intelligence

Select

BioND

Building the Bioscience industry in North Dakota one company at a time.


Richard Glynn
BioND CEO


Emily O'Brien
BioND COO

Adventures with Liz

Liz Markham, GNDC's Membership Director, is digging into the job! She's got a hunt for adventure and we are just trying to keep up! Ride along!

SWAG EXCHANGE

Liz recently caught up with Keith Lang from S&S Promotional Group! They had a great time talking about the ins and outs of the statewide promotional business. Keith and Liz shared stories...and yes, they exchanged a few goodies too. Liz learned how Keith, after running his own business for years, is now working from home and enjoying a more flexible schedule. Cheers to Keith and S&S Promotional Group for making work and swag look like a breeze!

UPCOMING GNDC EVENTS

February 13
Policy Outlook: Tax Policy
Virtual Meeting
9 AM

March 19
Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

Policy Outlook: Tax Policy

Feb 13 | Virtual

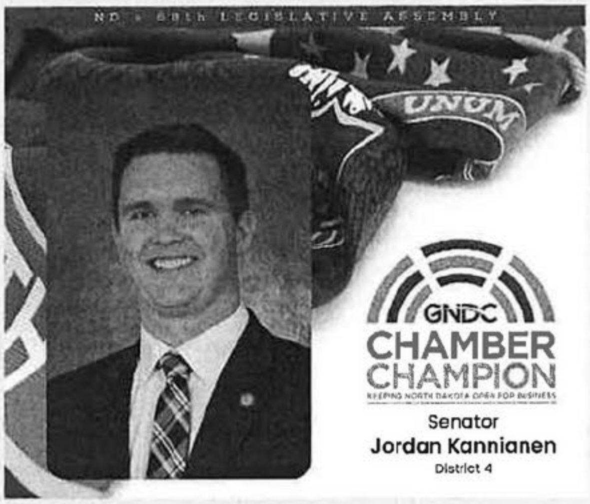
To receive call-in information, attendees will need to register in advance.

Register to Attend

Presenters

- **Sen. Jordan Kannianen**
- **Rep. Jared Hagert**

GNDC released the Legislative Report - with a special *How They Voted* Section. To showcase the work of pro-business legislators, we will be celebrating one each week.



Sen Jordan Kannianen (District 4) Stanley, is the Chair of Finance & Taxation and serves on Energy, Development and Transmission Committee. GNDC appreciates his thoughtful manner, dry humor, and crowd management. We look forward to chatting with him about Tax Policy at our February Policy Outlook!

WANTING TO OPT OUT?

If you want to unsubscribe from this 3x/week email but still receive all other GNDC communications - reply STOP to this email.
We will get you taken care of! After all, you still want to be in the know!

Lemieux, Kayla M.

From: Arik Spencer
Sent: Wednesday, January 10, 2024 9:26 AM
To: Beehler, Jace
Subject: RE: The Dakota Digest: The best morning briefing

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Hi Jace,

Yes, we would be happy to. Can you send me a brief write-up and perhaps a link readers can visit for additional details? It will go out next Tuesday, Wednesday, or Thursday, depending on when you get me the info.

Arik Spencer
CEO, President | Greater North Dakota Chamber
PO Box 2639, Bismarck, ND 58502
ndchamber.com | arik@ndchamber.com | 701.222.0929

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Wednesday, January 10, 2024 9:03 AM
To: Arik Spencer <arik@ndchamber.com>
Subject: RE: The Dakota Digest: The best morning briefing

Hi Arik,

Any way that you all would consider including a note or article about the upcoming State of the State on January 23 at 10:00am Mountain in your next Dakota digest?

Thanks,
Jace

From: Greater North Dakota Chamber <ndchamber+ndchamber.com@ccsend.com>
Sent: Wednesday, January 10, 2024 5:01 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: The Dakota Digest: The best morning briefing

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Link to Reuters

Both Sides of the Coin

Red Sea Attacks

[AP News] In the last four weeks, Houthi militants have attacked or seized commercial ships 12 times and still hold 25 members of the MV Galaxy Leader hostage in Yemen... The United Kingdom, Bahrain, Canada, France, Italy, Netherlands, Norway, Seychelles and Spain have joined the new maritime security mission, Austin said. Some of those countries will conduct joint patrols while others provide intelligence support in the southern Red Sea and the Gulf of Aden.

The U.S. and a host of other nations are creating a new force to protect ships transiting the Red Sea that have come under attack by drones and ballistic missiles fired from Houthi-controlled areas of Yemen, Defense Secretary Lloyd Austin announced Tuesday in Bahrain...

The left calls for greater international cooperation.

Contrary to common assumptions, U.S. military presence across the Middle East increased over

The right calls for a military response to deter both the Houthis and Iran.

At the same time, "Biden should make clear that the U.S. will not protect ships in the Red Sea that

Have you applied for the $500 Property Tax Credit?

Yes

Select

No, not yet

Select

Does not apply to me

Select

LEARN MORE: Primary Residence Credit | North Dakota [ND Tax]

[redacted]

What else are we reading?

Global and National

- Social media companies made $11 billion in US ad revenue from minors, Harvard study finds [AP News]
- The 2024 economy could be shockingly normal [Axios]
- Has the Stanley cup hype reached its peak? [NBC News]

North Dakota and Regional

- Minnesota adopts new, non-racist state flag, joins Utah, Mississippi, Michigan, Illinois in redesigning flags [Fox News]
- Supply-Chain Risk Management Program Is Aiding North Dakota's Cybersecurity [AFCEA]

By The Numbers

The minimum wage is going up in 22 states on Jan. 1

For Americans making minimum wage, it's an automatic raise — but it also ripples out. Typically, increasing the wage floor for the lowest earners pushes up pay for those who make a bit more than the minimum, as employers have to adjust pay scales upwards.

The big picture: More states are requiring a $15 an hour minimum wage — including New York, Maryland, and New Mexico — a dozen years after Fight for $15 kicked off its campaign.
Thanks to inflation, the dollar amount doesn't quite mean what it used to.

From: Greater North Dakota Chamber <ndchamber+ndchamber.com@ccsend.com>
Sent: Wednesday, January 10, 2024 5:01 AM
To: Beehler, Jace
Subject: The Dakota Digest: The best morning briefing

GREATER NORTH DAKOTA CHAMBER

DAKOTA DIGEST

Keeping North Dakota Open for Business Jan 10

Top of Mind Headline

Biden administration to unveil contractor rule that could upend gig economy

The administration of U.S. President Joe Biden will release a final rule as soon as this week that will make it more difficult for companies to treat workers as independent contractors rather than employees that typically cost a company more, an administration official said.

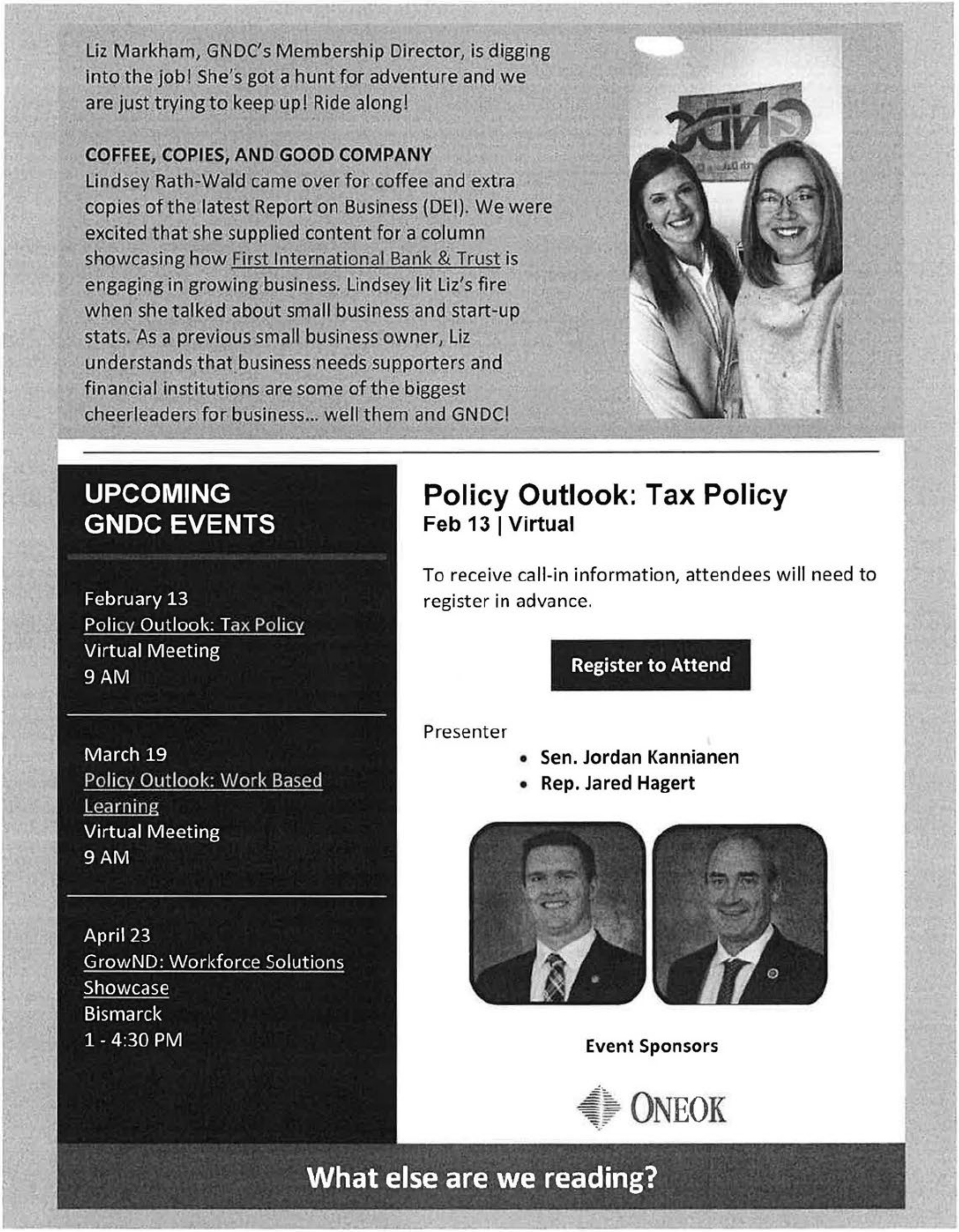
own military buildup and that of its proxies... The risks created by the sustained U.S. military presence in the Middle East can only be addressed by reducing that presence...
Concerns that Iran might be emboldened by such moves are overblown. Facing domestic political and economic pressure, Iran has little to gain from starting a regional war, and has instead pursued diplomatic efforts with neighbors in recent months. And its malign meddling across the region, while certainly a concern, is best countered through intelligence cooperation, maritime and air defense partnerships with allies, and targeted sanctions.
Frederic Wehrey and Jennifer Kavanagh, Los Angeles Times

and coast guard vessels are simultaneously ramming Philippine vessels. Beijing is taking this action within the Philippines's exclusive economic zone because it makes grand imperialist claims over the near entirety of the South China Sea...

The Philippines is a treaty defense ally of the U.S. Beijing is ultimately engaged in exactly the same action as the Houthis: attacking the rights of free navigation in international waters. In turn, it should be an absurd proposition for the U.S. to defend Chinese shipping interests.
Tom Rogan, Washington Examiner

Member Poll

Poll powered by BEK



Liz Markham, GNDC's Membership Director, is digging into the job! She's got a hunt for adventure and we are just trying to keep up! Ride along!

COFFEE, COPIES, AND GOOD COMPANY

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Policy Outlook: Tax Policy
Virtual Meeting
9 AM

March 19
Policy Outlook: Work Based Learning
Virtual Meeting
9 AM

April 23
GrowND: Workforce Solutions Showcase
Bismarck
1 - 4:30 PM

Policy Outlook: Tax Policy

Feb 13 | Virtual

To receive call-in information, attendees will need to register in advance.

Presenter

- **Sen. Jordan Kannianen**
- **Rep. Jared Hagert**

Event Sponsors

ONEOK

What else are we reading?

From: Williston Basin Petroleum Conference <wbpc@ndoil.org>
Sent: Monday, January 8, 2024 3:12 PM
To: Beehler, Jace
Subject: WBPC 2024 Registration Opens in TWO DAYS!

You don't often get email from wbpc@ndoil.org. Learn why this is important

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

BAKKEN NOW

MAY 14-16
BISMARCK, ND

Registration for the WBPC Opens in 2 DAYS!

We expect over 250 exhibitors and at least 2,000 attendees. There are still a few booths left so visit our website to BOOK NOW!

About the Williston Basin Petroleum Conference: The Williston Basin Petroleum Conference is the premier oil and natural gas conference focused on the Williston Basin and the Bakken and brings together key decision makers and industry experts to spur the progress and future development of this world-class resource. The conference alternates between North Dakota and Saskatchewan, Canada every other year and is sponsored by the North Dakota Petroleum Council, North Dakota Department of Mineral Resources and Government of Saskatchewan Ministry of the Economy and the Petroleum Technology Research Centre. For more information and to register, visit www.wbpcnd.com

CHECK OUT THE WEBSITE

Lemieux, Kayla M.

From:	Weber, Aaron (Hoeven) <Aaron_Weber@hoeven.senate.gov>
Sent:	Wednesday, January 3, 2024 4:12 PM
To:	Beehler, Jace
Subject:	FW: Register for API's State of American Energy (1/10)

You don't often get email from aaron_weber@hoeven.senate.gov. Learn why this is important

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

FYI

From: American Petroleum Institute <registrar@api.org>
Sent: Wednesday, January 3, 2024 2:35 PM
To: Weber, Aaron (Hoeven) <Aaron_Weber@hoeven.senate.gov>
Subject: Register for API's State of American Energy (1/10)

View in browser

API STATE OF AMERICAN ENERGY
2024

The American Petroleum Institute's

2024 State of American Energy

WEDNESDAY, JANUARY 10, 2024

www.api.org | Contact | Privacy Policy | Terms and Conditions

Connect with us on:

Email Preferences | Unsubscribe

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber+ndchamber.com@ccsend.com>
Sent: Wednesday, January 3, 2024 5:01 AM
To: Beehler, Jace
Subject: The Dakota Digest: The best morning briefing

***** **CAUTION**: This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

GREATER NORTH DAKOTA CHAMBER DAKOTA DIGEST

Keeping North Dakota Open for Business Jan 3

Top of Mind Headline

North Dakota lawmaker who used homophobic slurs during DUI arrest has no immediate plans to resign

A North Dakota Republican lawmaker has no plans to immediately resign, despite party leaders' calls for him to step down after he railed against police with profane, homophobic and anti-migrant language during a recent traffic stop that ended in his arrest on a charge of drunken driving.

along with the original document's requirements, in Article 2, that the president be at least 35 years old and born in the United States...
In that sense, the Colorado Supreme Court's holding is no more exotic than dozens of past court rulings that a candidate fails to meet constitutional qualifications such as age. And were we to adopt the view of Trump's lawyers, Colorado and other states could not exclude candidates from the ballot even if they plainly fail to satisfy age, residency, citizenship and other requirements. The potential political impact of the ruling, however, could not be more seismic.
Harry Litman, Los Angeles Times

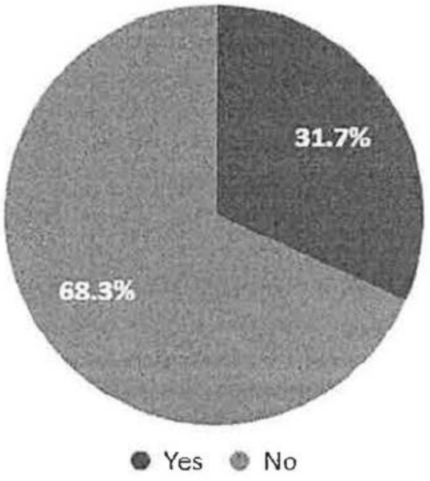
every place in between. You say Donald Trump is a threat to democracy? This finding is more a threat to democracy literally than anything Trump has ever done...

The decision is stayed pending an appeal to the United States Supreme Court. If SCOTUS lets this stand, we will spend 2024 with Democrats going state by state literally trying to fix the election unambiguously using an argument at least half the country will consider not only illegitimate, but possibly worth fighting in literal terms. January 6th will look like a child's birthday party in comparison.
John Podhoretz, Commentary

Member Poll

Poll powered by BEK

Did you make a New Year's resolution for 2024?



Do you have new, professional goals for 2024?

Yes

Select

No

Select

Policy Outlook: ESG Impacts
Virtual Meeting
9 AM

February 13
Policy Outlook: Tax Policy
Virtual Meeting
9 AM

April 23
GrowND: Workforce Solutions Showcase
Bismarck
1 - 4:30 PM

Register to Attend

Presenter

- **Kelvin Hullet, Kayla Ver Helst** - Bank of North Dakota

Event Sponsors

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

ONEOK

What else are we reading?

Global and National

- The biggest stories that defined U.S. business in 2023 [Axios]
- Transformation work continues: IRS expands business tax account access to S corporations, partnerships; adds ability to view business tax transcripts [IRS]
- Mickey Mouse will soon belong to you and me — with some caveats [AP News]

North Dakota and Regional

- I shopped at Trader Joe's in the Midwest and New York City. The prices were the same, but the experiences couldn't have been more different. [Business Insider]
- Gov. Burgum issues emergency declaration for North Dakota in wake of ice storm [InForum]
- Minnesota to implement new "blackout plates" in January [KTTC]

Lemieux, Kayla M.

From: Greater North Dakota Chamber <ndchamber+ndchamber.com@ccsend.com>
Sent: Tuesday, January 2, 2024 5:00 AM
To: Beehler, Jace
Subject: The Dakota Digest: The best morning briefing

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

GNDC

GREATER NORTH DAKOTA CHAMBER DAKOTA DIGEST

Keeping North Dakota Open for Business **Jan 2**

Top of Mind Headline

Burgum welcomes new record population estimate of 783,926 for North Dakota from U.S. Census Bureau

regulatory setbacks. The $1 billion open-pit mine near Babbitt and processing plant near Hoyt Lakes would be Minnesota's first copper-nickel mine.

Link to CBS News

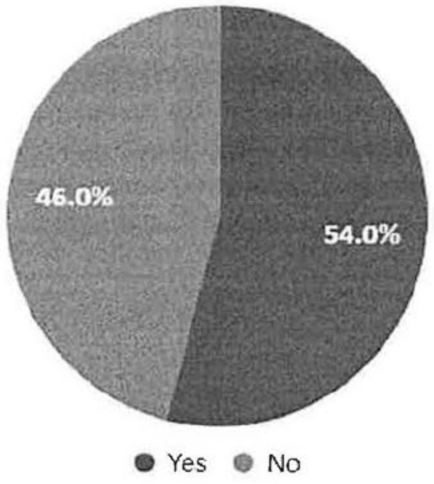
along Interstate 94 to Chicago and the Pacific Northwest.

Link to Bismarck Tribune

The Poll

Poll powered by BEK

Do you plan to take time off from work the week between Christmas and New Year?



Did you make a New Year's resolution for 2024?

Yes

Select

No

Select

FURTHER READING: The biggest mistake you make when setting New Year's resolutions — and how to stick to them [Business Insider]

BEK TV

bek.tv

National & Global

What Every Small Business Needs to Know About the Corporate Transparency Act

GNDC EVENTS

January 9
Policy Outlook: ESG Impacts
Virtual Meeting
9 AM

February 13
Policy Outlook: Tax Policy
Virtual Meeting
9 AM

April 23
GrowND: Workforce Solutions Showcase
Bismarck
1 - 4:30 PM

January 9 | Virtual

To receive call-in information, attendees will need to register in advance.

Register to Attend

Presenter

- **Kelvin Hullet, Kayla Ver Helst** - Bank of North Dakota

Event Sponsors:

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

ONEOK

What else are we reading?

Global and National

- What did you Google in 2023? 'Barbie,' Israel-Hamas war are among the year's top internet searches [AP News]
- Mapped: U.S. public pensions have a lot of investments in China [Axios]

North Dakota and Regional

- Coal miners lead paleontologists to partial mammoth fossil in North Dakota [CBS News]
- Ag-related North Dakota businesses get state funding [Bismarck Tribune]

From: Beehler, Jace
To: Gulleson, Connie M.
Subject: FW: 2024 API State of American Energy Speaker Invitation (1/10)
Date: Monday, December 11, 2023 4:12:35 PM
Attachments: image002.png
image003.png

For us to have further discussion about.

From: Rolf Hanson <Hansonr@api.org>
Sent: Monday, December 11, 2023 7:46 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Jace,

I hope all is well. I wanted to follow up to see if you have been able to confirm the Governor's availability for this event. We appreciate your consideration!

Regards,

Rolf Hanson
Vice President, State Government Relations
American Petroleum Institute
o: 202.682.8219
m: 571.512.8468

www.api.org

American
Petroleum
Institute

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Tuesday, November 28, 2023 6:26 AM
To: Kristin A. Westmoreland <WestmorelandK@api.org>
Cc: Rolf Hanson <Hansonr@api.org>
Subject: RE: 2024 API State of American Energy Speaker Invitation (1/10)

Thank you for the invitation. We will check on the schedule and get back as soon as we can.

Thanks,
Jace

From: Kristin A. Westmoreland <WestmorelandK@api.org>
Sent: Monday, November 27, 2023 12:57 PM
To: Beehler, Jace <jabeehler@nd.gov>
Cc: Rolf Hanson <Hansonr@api.org>
Subject: 2024 API State of American Energy Speaker Invitation (1/10)

Jace –

I hope this email finds you well and that you had a great Thanksgiving!

API President and CEO Mike Sommers would like to invite Governor Burgum to join him as a speaker at API's 2024 State of American Energy (SOAE) the morning of January 10 in Washington, DC. This in-person event will have a broad range on attendees including industry experts, Congressional staff, policymakers, and press who would benefit from hearing Governor Burgum's insights. Please see the attached invitation for additional information.

Should you have any questions, please don't hesitate to reach out to myself or Rolf Hanson, API Vice President for State Government Relations.

All the best,
Kristin

Kristin Westmoreland
Vice President and Chief of Staff
703.300.0385
e: westmorelandk@api.org
www.api.org
-
American
Petroleum
Institute

From: Kennedy, Mike
To: Lemieux, Kayla M.; Gulleson, Connie M.
Cc: Kosek, Triston T.
Subject: FW: A Powerful Beginning to the 31st Annual Williston Basin Petroleum Conference in Bismarck, ND
Date: Thursday, April 18, 2024 2:35:12 PM
Attachments: image.png
image.png

In case you need any of this info for the event there's a bunch of good stuff below.

-mk

From: Reva Kautz <rkautz@ndoil.org>
Sent: Monday, April 15, 2024 3:27 PM
To: Reva Kautz <rkautz@ndoil.org>
Subject: A Powerful Beginning to the 31st Annual Williston Basin Petroleum Conference in Bismarck, ND

BAKKEN NOW | WILLISTON BASIN PETROLEUM CONFERENCE

MAY 14-16, 2024

Bismarck Event Center, Bismarck, ND

31st Annual Williston Basin Petroleum Conference

A POWERFUL BEGINNING

You won't want to miss the Lunch and Learn discussion of **Energy Policy and Politics** with North Dakota Congressman Kelly Armstrong and Montana Congressman Ryan Zinke. It will be a great start to the Conference in Bismarck at Noon on May 14, 2024. We are looking forward to Continental Resources' Blu Hulsey facilitating this conversation as the session chair.

KELLY ARMSTRONG
North Dakota
Congressman

RYAN ZINKE
Montana
Congressman

Session Chair:

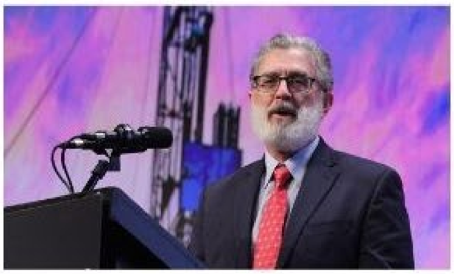
BLUE HULSEY
Continental
Resources

WILLISTON BASIN–THE PATH FORWARD

Lynn Helms, Director of the North Dakota Department of Mineral Resources, shared during his April 12th Director's Cut that North Dakota exceeded production of 5 billion barrels of oil from the Bakken and Three Forks formations at the end of February 2024.

FIVE BILLION BAKKEN BARRELS

Join the celebration at the conference at 5 PM on Tuesday, May 14, 2024.



Don't miss Governor Burgum's tribute to Director Helms on Wednesday, May 15th.

Lynn Helms' presentation regarding "The Path Forward" will be on Thursday morning, May 16th.

BUILD YOUR BUSINESS AT THE TRADE SHOW

TOP REASONS TO ATTEND :

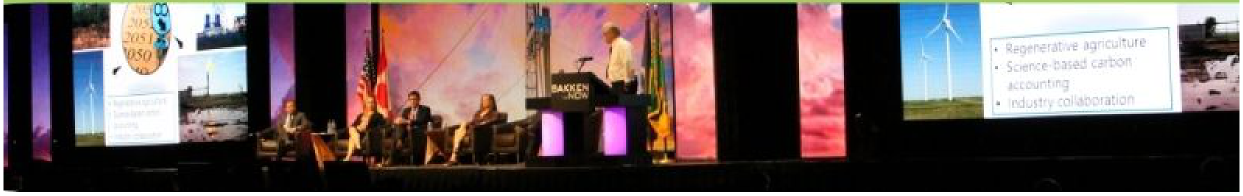
BAKKEN NOW | WILLISTON BASIN PETROLEUM CONFERENCE

- 70 + Speakers including Bakken CEOs and Industry Experts
- Multi-session workshops covering hot topics such as:
  - Advancing Bakken Technology
  - Operational Best Practices
  - Navigating Federal Regulations
  - Sustainability
  - Carbon Management
  - Workforce Solutions
  - Geology
- Sold Out Trade Show with indoor and outdoor exhibits
- Networking Opportunities during meals, breaks and multiple socials
- Build business connections
- First 1,000 to attend the 5 Billion Bakken Barrels celebration on May 14th will receive a limited-edition commemorative gift
- A chance to thank Lynn Helms, Director of North Dakota Department of Mineral Resources, for his years of service to the state before his retirement

CONNECT WITH DIGNITARIES

Presenters include Governor Doug Burgum, North Dakota Congressman Kelly Armstrong, Montana Congressman Ryan Zinke, North Dakota Attorney General Drew Wrigley, North Dakota Agricultural Commissioner Doug Goehring, and North Dakota Public Service Commissioner Julie Fedorchak.
Many state legislators also plan to attend.

REGISTER TODAY! www.wbpcnd.com



You can see the full agenda and to register for the conference with the WBPC website www.wbpcnd.com.

We look forward to seeing you in May!

Reva Kautz

Communications Director

North Dakota Petroleum Council

100 West Broadway, Suite 200

PO Box 1395

Bismarck, ND 58501

Office: 701.557.7744

rkautz@ndoil.org

www.ndoil.org

From: Beehler, Jace .
To: Gulleson, Connie M.
Subject: FW: Intro to AXPC
Date: Thursday, June 29, 2023 8:55:22 PM
Attachments: image001.png
image002.png

FYI. Could the Governor potentially participate in this?

From: Bradbury, Anne <anne.bradbury@axpc.org>
Sent: Tuesday, June 20, 2023 11:13 AM
To: Beehler, Jace . <jabeehler@nd.gov>; Zac Weis <zaweis@marathonoil.com>
Subject: RE: Intro to AXPC

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Hi Jace!
Realizing that your schedule has gotten significantly more hectic lately…I wanted to check back on this to see if it was still on the radar. I think it would be a great group for the Governor to meet with and we'd love to include him in dinner if he's able to attend. A full list of our board members can be found here.
Thank you,
Anne

From: Beehler, Jace . <jabeehler@nd.gov>
Sent: Wednesday, May 24, 2023 11:29 AM
To: Bradbury, Anne <anne.bradbury@axpc.org>; Zac Weis <zaweis@marathonoil.com>
Subject: RE: Intro to AXPC

Thank you for the invitation, Anne.

I will get this to our scheduler, and we will get back to you as soon as possible.

All the best,
Jace

From: Bradbury, Anne <anne.bradbury@axpc.org>
Sent: Wednesday, May 24, 2023 10:23 AM
To: Beehler, Jace . <jabeehler@nd.gov>; Zac Weis <zaweis@marathonoil.com>
Subject: RE: Intro to AXPC

You don't often get email from anne.bradbury@axpc.org. Learn why this is important

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Hi Jace! I hope you are well.
Following up on Zac's very kind introduction, I wanted to invite you to have dinner with my board of directors when they are in OKC on July 20th. Our board consists of the CEO's of the leading ND and national oil and gas producers—including our Chair, Lee Tillman of MRO.
We'd be delighted to have the Governor join us for discussion and fellowship. We expect Gov Stitt to join us as well.
Thanks for you consideration and please let me know if you have any questions.
Best,
Anne

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Monday, September 26, 2022 11:12 AM
To: Bradbury, Anne <anne.bradbury@axpc.org>; Zac Weis <zaweis@marathonoil.com>
Subject: RE: Intro to AXPC

Thank you, Zac and Anne.

We appreciate the reach out and the willingness stay connected with our team. Please let me know if the is an opportunity that would make sense for us to connect or a strategic time to touch base with your board.

Looking forward to working together!
Jace

Jace Beehler
Chief of Staff
Office of the Governor
701.328.2201 • 701.610.9431(m) • jabeehler@nd.gov • www.nd.gov

NORTH Dakota | Office of the Governor
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From: Bradbury, Anne <anne.bradbury@axpc.org>
Sent: Monday, September 26, 2022 8:44 AM
To: Zac Weis <zaweis@marathonoil.com>; Beehler, Jace <jabeehler@nd.gov>
Subject: RE: Intro to AXPC

Thanks Zac!
Hi Jace, it was so great the meet the Governor at the NDPC meeting last week. As Zac mentioned,

we represent most of the largest Bakken producers and work closely with the ND DC delegation on federal issues that impact industry. Would love to explore opportunities to work together more closely, and to increase connectivity with the Governor and my Board.
All the best,
Anne

From: Weis, Zachary A. (MRO) <zaweis@marathonoil.com>
Sent: Thursday, September 22, 2022 11:57 PM
To: jabeehler@nd.gov; Bradbury, Anne <anne.bradbury@axpc.org>
Subject: Intro to AXPC

Jace,
Making the connection with you to Anne Bradbury, CEO of American Exploration & Production Council. Anne followed the Governor yesterday after he spoke at the NDPC Annual Meeting. Anne and her team are an integral part of our industry, representing the US Oil & Gas and the interests of energy producing states in DC. I did a quick look at the AXPC membership and it looks like we have 10 large Bakken producing operators serving on the AXPC board, including Marathon Oil's CEO Lee Tillman who is currently the chairman of the board.

I know many of the AXPC board members know Governor Burgum individually. I want to make sure that you and the Governor know that if there is every any opportunity for us to assist or to open a dialogue with the Governor that we are always her to help.

Zac Weis
Government & Community Relations Manager
Marathon Oil Company
Mobile: 701-400-2989

From: Beehler, Jace
To: Gulleson, Connie M.
Subject: Fw: Registration Now Open for NDPC Annual Meeting in September
Date: Tuesday, July 30, 2024 2:51:23 PM

Hi Connie,

Please ensure this is on the Gov calendar as a hold.

Thank you

From: North Dakota Petroleum Council <ndpc@ndoil.org>
Sent: Tuesday, July 30, 2024 1:46 PM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: Registration Now Open for NDPC Annual Meeting in September

NDPC Logo

The NDPC Annual Meeting is Back in Watford City!

Join us September 17-19, 2024 in the heart of the Bakken!

The 43rd North Dakota Petroleum Council Annual Meeting is scheduled for September 17-19, 2024, at the Rough Rider Center in Watford City, ND.

Attendees can look forward to hearing from the Bakken's foremost industry leaders, networking with more than 400 industry professionals, and learning about the latest trends in oil and gas. From the socials to the Annual Industry Awards Luncheon to the knowledgeable speakers and panels presenting on what's new in the Bakken, there is something for everyone at the Annual Meeting!

Registration is now open!

Register

No longer wish to receive these kinds of emails? Log in to your Member Profile to update your email lists and preferences.

NDPC Logo

From: Eric Delzer
To: Reiten, John R.
Cc: Brady Pelton; Ron Ness
Subject: 200 Ways the Biden Administration and Democrats Have Made it Harder to Produce Oil & Gas
Date: Monday, March 11, 2024 4:05:12 PM
Attachments: Outlook-kuli0132.png

John,

Not sure if you've seen this yet but the IER updated the list they've been tracking since Biden took office and published a new report.

On March 8, 2024, the Institute for Energy Research (IER) published a comprehensive report titled "200 Ways the Biden Administration and Democrats Have Made it Harder to Produce Oil & Gas." This report meticulously details the various policies and executive actions undertaken by the Biden Administration that have significantly hindered oil and gas production in the United States. The report highlights changes in environmental regulations, shifts in financial policies, and international strategies that have collectively contributed to challenges faced by the domestic energy sector. The IER's analysis aims to shed light on the cumulative impact of these actions on energy production, economic growth, and energy security in the country.

200 things list IER.docx (instituteforenergyresearch.org)

It is a good resource for reference as it chronologically lists every action that has taken place since day 1 of the administration.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

IER INSTITUTE FOR ENERGY RESEARCH®

200 Ways the Biden Administration and Democrats Have Made it Harder to Produce Oil & Gas

President Biden and the Democrats in Congress and the states have a plan for American energy: make it harder to produce and more expensive to purchase. Since Mr. Biden took office, his administration and its allies have taken over 200 actions deliberately designed to make it harder to produce energy here in America. A list of those actions, which includes a few high-profile actions taken in states like New York and California, appears below.

On January 20, 2021,

1. Besides canceling the Keystone XL pipeline,
2. President Biden restricted domestic production by issuing a moratorium on all oil and natural gas leasing activities in the Arctic National Wildlife Refuge.
3. He also restored and expanded the use of the government-created social cost of carbon metric to artificially increase the regulatory costs of energy production of fossil fuels when performing analyses, as well as artificially increase the so-called “benefits” of decreasing production.
4. Biden continued to revoke Trump administration executive orders, including those related to the Waters of the United States rule and the Antiquities Act. The Trump-era actions decreased regulations on Federal land and expanded the ability to produce energy domestically.

On January 27, 2021,

5. Biden issued an executive order announcing a moratorium on new oil and gas leases on public lands
6. or in offshore waters
7. and reconsideration of Federal oil and gas permitting and leasing practices.
8. He directed his Interior Department to conduct a review of permitting and leasing policies.
9. Also, by Executive Order, Biden directed agencies to eliminate federal fossil fuel "subsidies" wherever possible, disadvantaging oil and natural gas compared to other industries that receive similar Federal tax treatments or other energy sources which receive direct subsidies.
10. This Biden Executive Order attacked the energy industry by promoting "ending international financing of carbon-intensive fossil fuel-based energy while simultaneously advancing sustainable development and a green recovery." In other words, the U.S. government would leverage its power to attack oil and gas producers while subsidizing favored industries.
11. Biden's EO pushed for an increase in enforcement of "environmental justice" violations and support for such efforts, which typically are advanced by radical environmental organizations and slip-and-fall lawyers hoping to cash in on the backs of energy consumers.

On February 2, 2021,

12. The EPA hired Marianne Engelman-Lado, a prominent environmental justice proponent, to advance its radical Green New Deal social justice agenda at the EPA, a signal to industry that it plans to continue its attack on American energy.

On February 4, 2021,

13. At the behest of the January 27th Climate Crisis EO, the DOJ withdrew several Trump-era enforcement documents which provided clarity and streamlined regulations to increase energy independence.

On February 19, 2021,

14. Biden officially rejoined the Paris Climate Agreement, which is detrimental to Americans while propping up oil production in Russia and OPEC and increasing the dependence of Europe on Russian oil and natural gas. It also benefits China, who dominates the supply chain for critical minerals that are needed for wind turbines, solar panels, and electric vehicle batteries.

On February 23, 2021,

15. The Biden administration issued a Statement of Administration Policy in support of H.R. 803 which curtailed energy production on over 1.5 million acres of federal lands.

On March 11, 2021,

16. The President signed ARPA, which included numerous provisions advancing Biden’s green priorities, such as a $50 million environmental slush fund directed towards “environmental justice” groups, including efforts advanced by Biden’s EO.
17. ARPA also included $50 million in grant funding for Clean Air Act pollution-related activities aimed at advancing the green agenda at the expense of the fossil fuel industry.

On March 15, 2021,

18. Biden's Securities and Exchange Commission sought input regarding the possibility of a rule that would require hundreds of businesses to measure and disclose greenhouse gas emissions in a standardized way, hugely increasing the environmental costs of compliance and disincentivizing oil and gas production.

On April 15, 2021,

19. The Federal Energy Regulatory Commission's policy statement outlines — and effectively endorses — how the agency would consider market rules proposed by regional grid operators that seek to incorporate a state-determined carbon price in organized wholesale electricity markets. This amounts to a de facto endorsement of a carbon tax that would be paid by everyday Americans in their utility bills.

On April 16, 2021,

20. At Biden's Direction, Secretary of the Interior Deb Haaland revoked policies in Secretarial Order 3398 established by the Trump administration including rejecting "American Energy Independence" as a goal;
21. rejecting an "America-First Offshore Energy Strategy;"
22. rejecting "strengthening the Department of the Interior's Energy Portfolio;"
23. and rejecting establishing the "Executive Committee for Expedited Permitting." These actions set the stage for the unprecedented slowdown in energy activity by the Interior Department, steward of 2.46 billion acres of federal mineral estate and all its energy and mineral resources.

On April 22, 2021,

24. Biden issued the U.S. International Climate Finance Plan to funnel international financing toward green industries and away from oil and gas.

On April 27, 2021,

25. The Biden administration issued a Statement of Administration Policy in support of S.J. Res. 14 which rescinded a Trump-era rule that would have cut regulations on American energy production.

On April 28, 2021,

26. Biden's EPA issued a Notice of Reconsideration that would propose to revoke a Trump-era action that revoked California's waiver for California's Advanced Clean Car Program (Light-Duty Vehicle Greenhouse Gas Emission Standards and Zero Emission Vehicle Requirements).

On May 5, 2021,

27. This proposed Fish and Wildlife Service Rule revokes a Trump administration rule and expands the definition of "incidental take" under the Migratory Bird Treaty Act (MBTA). The rule would impact energy production on federal lands, increasing regulatory burdens.

On May 20, 2021,

28. Biden issued an executive order on Climate-Related Financial Risk that would artificially increase regulatory burdens on the oil and gas industry by increasing the "risk" the federal government undertakes in doing business with them.

On May 28, 2021,

29. Biden's FY 2022 revenue proposals include nearly $150 billion in tax increases directly levied against the oil and gas energy producers.

On July 28, 2021,

30. This Department of Energy determination increases regulatory burdens on commercial building codes, requiring green energy codes to disincentivize natural gas and other energy sources. DOE readily admits they ignored efforts private industry is making on their own and utilized the questionable "social costs of carbon" to overstate the public benefit.
31. The Executive Order also kicked off the development of more stringent long-term fuel efficiency and emissions standards, a backdoor way to compel the electrification of vehicles.

On August 11, 2021,

32. The White House released a letter from Jake Sullivan begging OPEC+ (OPEC plus Russia) to produce more oil.

On September 3, 2021,

33. Biden's Department of Transportation issued a proposed rule that would update the Corporate Average Fuel Economy Standards for Model Years 2024–2026 Passenger Cars and Light Trucks to increase fuel economy regulations on passenger cars and light vehicles. The modeling calculated "fuel savings" by multiplying fuel price with 'avoided fuel costs' to disincentivize gasoline by making it more costly to afford ICE cars and trucks.

On September 9, 2021,

34. NASA and the FAA launched a partnership to reduce "fuel use and harmful emissions" by strong-arming industry to adopt elements of their green agenda.
35. The Department of Education's Climate Adaptation Plan (CAP) includes efforts to incorporate the green agenda into as many guidance and policies as possible, effectively leveraging the department as an anti-fossil fuel propaganda tool.

On October 4, 2021,

36. The FWS published its final rule revoking Trump-era actions which eased burdensome regulations on energy action.

On October 7, 2021,

37. The Council on Environmental Quality revoked Trump administration NEPA reforms that reduced regulatory burdens by reinstating tangential environmental impacts of proposed projects.

38. Biden announced plans to designate the Northeast Canyons and Seamounts Marine National Monument, a move counter to Trump's reversal of a similar Obama-era proclamation. Trump aimed to allow energy exploration in the area to increase energy independence.
39. The U.S. Department of Agriculture's (USDA) CAP includes efforts to switch fuel away from oil and natural gas and subsidize more costly, less efficient fuel sources.
40. As part of its CAP, EPA intends to incorporate Biden's Green New Deal agenda throughout its rulemaking process.

On October 21, 2021,

41. This report paints climate change, and therefore oil and gas producers, as a "risk to financial stability." The report recommended the "climate disclosures" later set forth by the Biden administration.

On October 28, 2021,

42. Rep. Rho Khanna interrogated oil CEOs about why they were increasing production as their 'European Counterparts' were lowering their own.

On October 29, 2021,

43. The Bureau of Land Management announced the use of social costs of carbon in decision-making for approving permits for oil and gas drilling. This devalues the economic benefits of energy production on federal lands.

On October 30, 2021,

44. The Department of Labor issued a final ESG Rule that would require fiduciaries to consider the economic effects of climate change and other so-called environmental, social and governance (ESG) factors when evaluating funds for retirement plans. The rule would strongly encourage fiduciaries to draw capital from domestic energy development in oil and natural gas to renewables.

On November 2, 2021,

45. The Biden administration led a “Global Methane Pledge” to reduce global methane emissions by 30 percent by 2030. Neither Russia nor China signed the pledge, increasing the world’s reliance on these two countries for energy-related imports and disadvantaging the U.S. oil and natural gas industry, as well as large consumers of energy such as industrial manufacturing and agriculture.

On November 4, 2021,

46. Biden committed to “ending fossil fuel financing abroad,” targeting the global fossil fuel industry, thereby disadvantaging them, which increases global oil and gas prices. Further, key countries, like China, did not sign the pledge, so the pledge harms signatories while empowering adversaries. This is another case of unilateral economic and energy disarmament.

On November 5, 2021,

47. Biden Energy Sec. Granholm laughed at questions about boosting oil production.

On November 12, 2021,

48. New Source Review: These broad, overreaching regulations target new, modified, and reconstructed oil and natural gas sources, and would require states to reduce methane emissions from hundreds of thousands of existing sources nationwide for the first time. The Proposed Rule follows the President's Day 1 Climate EO and the passage of the S.J. Res. 14, a CRA rescinding Trump-era energy independence policies. The proposed rule spends several paragraphs dismissing the effects of the rule on the oil and gas industry and misleadingly applies its effects on the industry to only the "140,000" (an underestimate of the over 220,000) employees directly involved in extraction. This means it ignores the nearly 10 million other people working in the oil and gas industry and the impacts to the oil and gas economy more broadly.

On November 15, 2021,

49. Biden's Interior Department announced plans to withdraw Chaco Canyon from oil and gas drilling for 20 years.
50. The Biden administration nominated Saule Omarova to serve as Comptroller of the Currency. Omarova's past comments speak for themselves: "A lot of the smaller players in [the fossil fuel] industry are going to, probably, go bankrupt in short order—at least, we want them to go bankrupt if we want to tackle climate change," she said.

On November 17, 2021,

51. HUD's CAP leverages the Community Development Block Grant to advance 'environmental justice' efforts.
52. Biden calls on the FTC to probe "anti-consumer behavior" by energy companies.

On November 19, 2021,

53. Biden endorsed several oil and gas provisions in the Build Back Better Bill, including a new tax on methane, of up to $1500 per ton;
54. prohibiting energy production in the Arctic and offshore leasing on the Outer Continental Shelf (OCS) in the Atlantic, Pacific and Eastern Gulf of Mexico Planning Areas;
55. increased fees and royalties for onshore and offshore oil and gas production;
56. a new $8 billion tax on companies that produce, process, transmit or store oil and natural gas starting in 2023;
57. limited ability of energy producers to claim tax credits for upfront and royalty payments in foreign countries – amounting to a tax increase on domestic energy producers;
58. and a 16.4 cent tax on each barrel on crude oil – up from 9.7 cents – a $13 billion tax increase on oil production.

On November 26, 2021,

59. Biden's Interior Department issued its report on the Federal Oil and Gas Leasing Program includes recommendations to raise rents and royalty rates on oil and gas producers, even though federal energy production already lags that from state and private lands.

On December 14, 2021,

60. The EPA launched a revamp of its Office of Civil Rights to add so-called environmental justice enforcement as a key pillar in enforcing Title VI civil rights complaints. The agency's announcements mean social justice claims against, among others, the oil and gas industry will increase costs and penalties that have specious connections to its environmental mission.

On December 21, 2021,

61. Biden's Department of Transportation issued its Final Rule revoking Trump-era actions which prevented California from arbitrarily becoming the national standard for fuel emissions. The rule set the stage for the administration to reinstate California's waiver, and, since automakers do not make different cars for different states, the rule would allow California's radical environmental policies to reach nationwide, forcing people nationwide to pay for vehicles meeting California's standards.

On December 30, 2021,

62. Biden's EPA issued its Final Rule for increased "fuel efficiency standards." According to the Final Rule, "These standards are the strongest vehicle emissions standards ever established for the light-duty vehicle sector. The rule, in responding to comments, claims "energy security benefits to the U.S. from decreased exposure to volatile world oil prices" suggesting that decreasing oil and gas production in the U.S. will result in less exposure to the international oil and gas market because they will be disincentivizing vehicles that use oil and gas. The rule also claims that it will result in "fuel savings" entirely due to less use of fuel.

On January 13, 2022,

63. DOE announced an initiative to hire 1,000 staffers for their Clean Energy Corps, a group of staff dedicated to Biden's promise to destroy fossil fuels.

On January 14, 2022,

64. Biden nominated Sarah Raskin to serve as Vice Chair of the Federal Reserve. She was deemed so radical in her belief that fed policy should be dictated by environmental policy that she gained a bipartisan opposition and had to withdraw her nomination.

On February 9, 2022,

65. A proposed rule on Coal and Oil Power Plant Mercury Standards would revoke a Trump-era rule that cut red tape on coal and oil-fired power generators and followed the Supreme Court's rejection of an earlier Obama administration rule. This would effectively reinstate Obama-era regulations which sought to increase regulations on coal and oil-fired power plants.

On February 18, 2022,

66. FERC updated a 23-year-old policy for assessing proposed natural gas pipelines, adding new considerations for landowners, environmental justice communities, and other factors. In a separate but related decision, the commission also laid out a framework for evaluating projects' greenhouse gas emissions.

On February 21, 2022,

67. The Biden administration paused working all new oil and gas leases on Federal land in response to a judge blocking their arbitrary use of social costs of carbon, unnecessarily hurting domestic oil and gas production.

On February 28, 2022,

68. The Ozone Transport Proposed Rule would expand federal emissions regulations over a wider geographic region and over a wider array of sources, including the gathering, boosting and transmission segments of the oil and gas sector. Integral energy production states like Nevada, Utah and Wyoming would be required to jump through more red tape.

On March 1, 2022,

69. Refusal To Appeal adverse leasing court decision: The Biden administration refused to appeal an unprecedented decision to vacate an offshore oil and gas leasing sale held in November 2021. This means under Biden, the U.S. has not held one successful lease sale offshore.
70. Certification of New Interstate Natural Gas Facilities: This policy statement increases climate change regulations for new interstate natural gas facilities.

On March 8, 2022,

71. President Biden tried to deflect from his anti-energy record saying there are 9,000 issued leases on federal lands without current drilling. This is true and it's also true that this is the lowest percentage of unused leases in at least 20 years — in other words, lease utilization is at a multi-decade high.

On March 9, 2022,

72. EPA Reinstates California Emissions Waiver: The EPA reinstated California's emissions waivers, allowing the state to set its own greenhouse gas emissions standards, standards which will likely be adopted nationwide and are sure to make vehicles more expensive. The practical effect is that California is setting policy for people in all the other states despite their terrible record of energy inflation.

On March 11, 2022,

73. Natural Gas Infrastructure Project Reviews: This interim regulation will increase the regulatory burden on natural gas facilities by, among other things, requiring climate change impacts be considered when determining whether a project is in the public interest.

On March 16, 2022,

74. Doubling Down on Social Costs of Carbon: The 5th Circuit Court of Appeals reinstated the dubious social costs of carbon metric which had been rejected by another court by issuing a stay on the lower court's ruling. The ruling itself cast doubt on the lower court's ruling. The Biden administration argued against the lower court's ruling to reinstate the SCC metric. The Social Cost of Carbon is a "made-up" number designed to make any hydrocarbon project in the U.S. more expensive. It is an "end-around" the politically difficult carbon tax most of the Green Establishment supports.

March 21, 2022,

75. SEC Proposed Rule on Mandatory Climate Disclosures: The SEC's proposed rule would require public companies to disclose greenhouse gas emissions
76. and their exposure to climate change. This rule would massively increase so-called environmental costs of compliance and, in tandem with so-called social costs of carbon, artificially disincentivizing oil and gas production.

March 28, 2022,

77. Army Corps of Engineers' Review of its Nationwide Permit 12 for Oil or Natural Gas Pipeline Activities: The corps announced it would be reviewing NWP 12 late last month as part of Biden's day-1 executive order on climate change mandating all federal agencies ensure their work is in line with its climate and environmental objectives. The review is part of a long list of actions that confuse and delay permitting for critical infrastructure. This makes pipelines harder to build and improve in the U.S.

March 30, 2022

78. Environmental Justice Advisory Council Meeting: The WHEJAC will hold its first two meetings to, among other things, advance Green New Deal priorities including "environmental justice and pollution reduction, energy, climate change mitigation and resiliency, environmental health, and racial inequity."

March 31, 2022

79. President Biden announces that he will sell one million barrels of oil a day from the Strategic Petroleum Reserve for the next six months.
80. Biden wants to penalize oil companies with unused leases: President Biden called on Congress to pass legislation enacting "use it or lose it" fines on wells that oil companies have leased from the federal government but have not used in years and "on acres of public lands that they are hoarding without producing… Companies that are producing from their leased acres and existing wells will not face higher fees." The extra fees on federally leased land are on top of rents that the oil companies pay to hold the leases, "bonus bids" paid by the winning bidder

at lease sales and the fact that 66 percent of federal leases are currently producing oil. This is simply a deflection from the Biden administration's war on affordable North American energy supplies.

81. Biden's Budget Contains More Anti-Oil Proposals: President Biden's budget for the fiscal year 2023 is $5.8 trillion. It contains large amounts of climate spending and anti-oil and gas policies that did not get passed in his Build Back Better bill last year.
82. Biden is seeking $50 billion for programs to address climate change,
83. including $18 billion to build the U.S. government's resilience to climate change,
84. $3.3 billion in funding for clean energy projects and at least $20 million for a new "Civilian Climate Corps."
85. To help pay for the increased climate spending, Biden is asking Congress to eliminate tax provisions that aid domestic energy production,
86. including tax deductions for intangible drilling costs and low-production wells that enable small producers in the United States to produce oil. Removing these deductions will lower domestic output while further raising already high oil and gasoline prices.

April 5, 2022,

87. Biden's Department of Energy Office of Fossil Energy and Carbon Management releases a "Strategic Vision" with no discussion of increasing domestic fossil energy production: The Department of Energy is statutorily required to carry out research and development with "the goal of improving the efficiency, effectiveness, and environmental performance of fossil energy production, upgrading, conversion, and consumption." (42 USC 16291) However, the Biden Department of Energy has no interest in increasing fossil energy production.

Despite the requirements of the law, the Strategic Vision is only about "Advancing Justice, Labor, and Engagement; Advancing Carbon Management Approaches toward Deep Decarbonization; and Advancing Technologies that Lead to Sustainable Energy Resources."

April 12, 2022,

88. Biden extended the availability of higher biofuels-blended gasoline during the summer to lower gasoline costs and to reduce reliance on foreign energy sources. The measure will allow Americans to buy E15, a gasoline blend that contains 15 percent ethanol from June 1 to September 15. Oil refiners are required to blend some ethanol into gasoline under a pair of laws, passed in 2005 and 2007, known as the Renewable Fuels Program, intended to lower the use of oil and greenhouse gas emissions and reduce dependency on foreign oil by mandating increased levels of ethanol in the nation's fuel mix every year. However, since the passage of the 2007 law, the mandate has been met with criticism that it has contributed to increased fuel prices and has done little to lower greenhouse gas emissions. With looming food shortages already acknowledged by President Biden, turning his back on domestic energy production while dedicating even more food to make energy inefficiently is not wise.

April 15, 2022,

89. Biden announced 144,000 acres of the federal mineral estate opened for oil and gas leasing — just 0.00589 percent of the 2.46 billion acres the American people own. White House Press Secretary Jen Psaki said, "Today's action…was the result of a court injunction that we continue to appeal, and it's not in line with the president's policy, which is to ban additional leasing."
90. The administration announced it would resume leasing, but with a royalty rate almost 50 percent higher.
91. Withdrawal of M-37046 and
92. reinstatement of M37039: "The Bureau of Land Management's Authority to Address Impacts of its Land Use Authorizations Through Mitigation" The Interior Department reversed a Trump administration decision which limited the scope of "compensatory mitigation" the Department could force upon projects on federal land as a condition of receiving a permit, which will hit energy and mining projects especially hard. Under the new guidance, opponents in the federal government could require mitigation located far from the project with little relevance, effectively giving bureaucrats a blank check to request whatever they wish of a permit seeker with little controls. This decision was made less than a week after the DOI Inspector General reported that there were no controls or apparent records justifying previous versions of this program, and warned they may have to review the overall program again. This is a "3rd world" approach giving government officials the latitude to effectively deny a project by assessing "compensatory mitigation" so expensive as to make it uneconomic, or to fund their pet projects by extorting additional funds from a permit-seeker.

April 19, 2022,

93. Biden Restores Climate to NEPA: The Biden administration completed reforms on how agencies implement the National Environmental Policy Act, effectively undoing one of the Trump administration's most important environmental regulatory rollbacks. This opens the door for officials to cook up whatever justification they desire to impede energy development under the guise of NEPA.

April 20, 2022,

94. White House Climate Advisor Gina McCarthy states on MSNBC that "President Biden remains absolutely committed to not moving forward with additional drilling on public lands."

April 21, 2022,

95. U.S. Climate Envoy John Kerry said the world's reliance on natural gas should be limited to a decade. He said, "We have to put the industry on notice: You've got six years, eight years, no more than 10 years or so, within which you've got to come up with a means by which you're going to capture, and if you're not capturing, then we have to deploy alternative sources of energy." Repeated statements like this from administration officials tell investors not to sponsor energy investments in the U.S., since it implies the use of those energy sources will be limited by the government.

April 25, 2022,

96. Biden reverses Trump's Alaska oil plan: The Biden administration released a management plan for the National Petroleum Reserve Alaska, an Indiana-sized area reserved for oil and gas leasing. The final decision reverses a Trump-era plan that had opened most of the reserve to oil and gas leasing and withdraws some of the most prospective oil and gas areas from consideration.

April 28, 2022,

97. The Biden administration admitted to using faulty modeling which overestimated wildlife effects, delaying permitting on existing leases.

May 18, 2022,

98. The Biden administration announced they were canceling a lease sale of over one million acres in the Cook Inlet in Alaska.
99. At the same time, the Biden administration announced they were canceling a lease sale in the Gulf of Mexico.

May 19, 2022,

100. HR. 7688 is named the "Consumer Fuel Price Gouging Prevention Act," and it would give the President vast powers to set price controls by executive fiat. If passed, this legislation will cause even more harm to American energy consumers. Price controls don't work, and our experience during the gas lines of the 1970s should remind us that price controls will lead to shortages
101. S.4214 is a similar "price gouging" bill taken up in the Senate.

June 2, 2022,

102. The Biden administration settled with environmental litigants to do what the Biden administration wanted to do and more thoroughly analyze the climate impacts of oil and gas leasing on 4 million acres of federal lands. This provides more delay, potential litigation about sufficiency, and more uncertainty about investment.
103. Biden's EPA announced they were allowing states greater power to stop roads, dams, shopping malls, housing developments, wineries, breweries, pipelines, coal terminals, and other projects using Section 401 of the Clean Water Act.

June 7, 2022,

104. Biden's EPA deals a death blow to Pebble Mine in Alaska. Citing its authority under the 1972 Clean Water Act, EPA proposed a legal determination that would ban the disposal of mining waste rock in the Bristol Bay watershed. Pebble is one of the world's largest copper deposits –essential for electrification—and holds enormous quantities of additional minerals, including strategic ones.

June 8, 2022,

105. Biden reduces fees on renewables while raising them on oil and gas. President Biden's Interior Department announced it will reduce the fees on renewable projects on federal lands after announcing recently that royalty rates and rents would increase as much as 50% for oil and gas projects on federal lands.

June 28, 2022,

106. President Biden considers new regulations that would hamper the largest oil-producing area in the world. His latest consideration is EPA implementing new requirements that would curb drilling across parts of the Permian Basin—the world's biggest oil field that straddles Texas and New Mexico.

July 6, 2022,

107. President Biden releases his draft offshore lease plan. The plan includes an option with zero lease sales. There is the potential for ten potential new leases in the Gulf of Mexico and one in the Cook Inlet off the southern coast of Alaska. There are no new leases in federal waters off the Atlantic and Pacific coasts. Biden's plan is in sharp contrast to President Trump's proposed offshore lease plan that had 47 new offshore drilling leases, including in the Atlantic and Pacific oceans. President Trump had proposed a vast expansion of drilling sales to cover more than 90 percent of coastal waters, including areas off California and new zones in the Atlantic and Arctic. The earliest Biden's offshore lease program could be finalized is likely late fall.

July 7, 2022,

108. The Biden administration proposes a strict appliance standard rule for furnaces, the goal of which is to increase the upfront cost of using natural gas furnaces so great that people will switch to electric heating.

July 14, 2022,

109. Biden sells oil to China from the SPR. Biden has sold more than five million barrels of oil from the SPR to European and Asian nations instead of U.S. refiners, compromising U.S. energy security. Biden's Energy Department in April announced the sale of 950,000 barrels from SPR to Unipec, the trading arm of the China Petrochemical Corporation, which is wholly owned by the Chinese government. China purchased that oil from U.S. emergency reserves to bolster its own stockpile. China has been buying large amounts of oil for its reserves since the early COVID lockdowns when prices were low due to demand destruction.

July 15, 2022,

110. Biden's Federal Highway Administration, without authority to do so, proposed requiring all states to track and reduce on-road vehicle greenhouse gas emissions.

August 16, 2022,

111. President Biden signs the Inflation Reduction Act (IRA), which includes new taxes on natural gas extraction and methane leaks, and
112. Superfund taxes on crude oil and its related products, and
113. An extension of biofuel tax credits and a new tax credit for sustainable aviation fuel. These biofuel tax credits will encourage existing petroleum refining capacity to convert to biofuels, making it harder for Americans to get the petroleum fuel products they need for transportation and home heating. These incentives will make the United States import more petroleum products from

countries with additional capacity such as China and the Middle East, while committing more agricultural products to fuel, rather than food.

114. IRA: The law also encourages states to adopt California's plan to phase out gas-powered vehicles by 2035.

August 17, 2022,

115. A federal judge reinstated a moratorium on coal leasing from federal lands that had been implemented during the Obama administration and was lifted under President Donald Trump. The ruling from U.S. District Judge Brian Morris requires government officials to conduct a new environmental review prior to resuming coal sales from federal lands. According to the judge, the government's previous review of the program had not adequately considered the impacts of climate change from coal's greenhouse gas emissions, among other effects.

August 18, 2022

116. Secretary of Energy Jennifer Granholm sent a letter to refiners threatening "to deploy emergency actions" against the industry if they continue to export refined products or otherwise fail to build refined product inventories. This ignores the record of increasing exports of petroleum coinciding with rising production in the U.S.

August 22, 2022,

117. U.S. Appeals Court reinstates Biden's ban on oil and gas leasing

September 6, 2022

118. The Biden administration reached an agreement with environmental groups to halt drilling permits on over 58,000 acres of land in a sue-and-settle case.

September 12, 2022,

119. EPA announced they rejected Cheniere Energy's LNG appeal to exempt two turbines at LNG export terminals from a hazardous pollution rule despite the needs of the Europeans and others for LNG and Biden's promises to help allies with supplies.

September 19, 2022

120. The Department of Energy announces the sale of an additional 10 million barrels of oil from the SPR.

September 20, 2022,

121. The Biden administration is expected to soon finalize a rule banning oil and gas leasing near Chaco Culture National Historical Park opposition from local Indigenous leaders, who say the administration's rule would prevent them from collecting royalties on their land.

September 30, 2022,

122. Secretary of Energy Jennifer Granholm and senior White House officials met with U.S. refiners. The Biden administration officials threatened the refiners with an export ban.

October 5, 2022,

123. The Biden administration is reportedly working to wind down sanctions against Venezuela's authoritarian government in exchange for oil production. This ignores that Venezuelan crude oil is much more carbon intensive than the domestic oil the Biden Administration is restricting, or Canadian oil which would have been transported via the Keystone XL pipeline.

October 7, 2022,

124. The Securities and Exchange Commission announced that it was reopening the comment period on the ESG rule because a "technological error" resulted in the deletion of some public comments. But the SEC only gave people 14 days to figure out if their comment was deleted and to submit a comment again.

October 2, 2022,

125. Biden administration officials lobbied the Saudis and other members of OPEC+ to hold off reducing oil output until after the midterm elections.

October 6, 2022,

126. The Department of the Interior moves forward with some leasing but notes that they are “mandated” by the Inflation Reduction Act. In other words, DOI is trying not to lease unless mandated by an act of Congress. This ignores that current law requires them to lease periodically, which they are honoring in the breach.

November 2, 2023

127. President Biden threatens oil companies with a windfall profits tax—again. “Their profits are a windfall of war,” Mr. Biden said, referring to the Russian invasion of Ukraine as the reason for high prices for oil and gasoline. Biden could easily increase domestic oil production by changing his anti-oil and gas policies that began on his first day in office.

November 9, 2022

128. California proposes banning new diesel trucks by 2040. The California Air Resources Board (CARB) proposed a regulation that would require manufacturers to sell only “zero-emission” medium and heavy-duty vehicles in the state by 2040.

November 16, 2022

129. The U.S. supports the phase out of hydrocarbon fuel sources at COP27.

November 17, 2022

130. Biden releases more stringent requirements to EPA's proposed methane rule at COP27. At the Conference of the Parties (COP27) in Egypt, President Biden's Environmental Protection Agency (EPA) released the text of a supplemental proposed rule regulating methane emissions from the oil and natural gas industries that is *more stringent* than the original proposed rule in 2021. The 2021 rule targets emissions from existing oil and gas wells nationwide, rather than focusing only on new wells as previous EPA regulations have done. The new rule released at COP27, however, includes *all drilling* sites, even smaller wells that emit less than 3 tons of methane per year. Small wells currently are subject to an initial inspection but are rarely checked again for leaks. The new proposal also requires operators to respond to credible third-party reports of high-volume methane leaks. These more stringent requirements result in a near doubling of the economic costs, which are estimated to produce a 13 percentage point increase in reduced emissions from 2005 levels by 2030. Increasing costs will increase bills for consumers at a time when natural gas prices are already expected to climb.

131. Federal government grants lesser prairie chicken ESA protections.

November 29, 2022

132. EPA proposes exorbitant estimates for the social cost of carbon. President Biden's Environmental Protection Agency (EPA) has proposed a new estimate for the social cost of carbon emissions that nearly quadruples the interim figure from the Obama Administration. The Biden administration has been using the Interagency Working Group's interim value of $51 per metric ton of carbon dioxide, but EPA has proposed increasing it to $190.

November 30, 2022

133. Instead of relying on the scientific method, the Biden administration instructed regulatory agencies to apply "indigenous knowledge" to "research, policies, and decision making."

December 7, 2022

133. President Biden seeks fossil fuel-free federal buildings and bans natural gas.

December 8, 2022

134. The Bureau of Land Management piles its methane rule atop those set by EPA and Congress. BLM's proposal would tighten limits on gas flaring on federal land and require energy companies to better detect methane leaks. The rule would impose monthly limits on flaring and charge fees for flaring that exceeds those limits.

December 23, 2022

135. California's regulators release their net zero plan. California regulators approved a plan to reduce the state's carbon-dioxide emissions by 85 percent from 1990 levels by 2045, thereby reaching carbon neutrality, meaning the state will remove as many emissions from the atmosphere as it emits. It aims to do so in part by reducing fossil fuel demand.

January 10, 2023

136. U.S. Interior Department names Elizabeth Klein to oversee offshore energy. She had initially been nominated by the White House to be the Deputy Interior Secretary under current chief Deb Haaland but was withdrawn from consideration in March 2021 amid opposition from moderate Alaska Republican Senator Lisa Murkowski, whose vote was needed for her confirmation, over concerns that Klein was opposed to oil development.

January 12, 2023

137. EPA's proposed rule regarding the Clean Water Act. The rule would expand the EPA and Army's regulatory oversight to include traditionally navigable waters, territorial seas, interstate waters and, "upstream water resources that significantly affect those waters." According to the two agencies, the revised rule is based on definitions that were in place before 2015. Farming groups, oil and gas producers, and real estate developers criticized the regulations as overbearing and burdensome to business, and, in particular, the ruling has the potential to affect natural gas infrastructure projects. It also would exert federal control over lands not owned by the federal government.

January 17, 2023

138. Biden appointee proposes ban on gas stoves. Richard Trumka Jr., a Biden commissioner on the CSPC, told *Bloomberg* the ban is justified because gas stoves increase respiratory problems such as asthma among children, which is a myth promoted by environmentalists whose real agenda is not to reduce asthma but to ban natural gas. Gas stoves are used in about 35 percent of households nationwide, or about 40 million homes. The household figure is closer to 70 percent in some states, such as California and New Jersey. Other states where many residents use gas stoves include Nevada, Illinois, and New York.

January 31, 2023

139. The Biden administration blocks Minnesota's Twin Metals Mine. The Biden administration blocked plans for a major copper, nickel and cobalt mine in northern Minnesota that could have helped supply minerals for his "net-zero" plans. The "Twin Metals Project" would have tapped the Duluth Complex within the Superior National Forest, where 95 percent of the nation's nickel reserves and 88 percent of American cobalt reserves are found.

February 3, 2023

140. The Biden administration blocks the development of Alaska's Pebble Mine. The U.S. Environmental Protection Agency blocked the development of the proposed Pebble mine–the most significant undeveloped copper and gold resource in the world–because of stated concerns about its environmental impact on Alaska's aquatic ecosystem.

March 3, 2023

141. Biden EPA approves Midwest governors’ request for year-round E15 sales. The Biden administration is recommending for approval a rule that would allow expanded sales of gasoline with a higher ethanol blend (15 percent ethanol), based on a request from governors in Midwest states.

March 9, 2023

142. Biden administration attacks oil and gas in FY24 budget proposal.

March 10, 2023

143. Biden’s offshore oil and gas lease plan was delayed by 18 months. President Biden’s oil and gas offshore lease plan is late and will be even later as the Interior Department argues it needs until December to finalize the plan. It told a court it needs the rest of the year to complete an analysis on the delayed five-year program, which will replace the expired 2017-2022 program.

March 14, 2023

144. Biden withdraws more areas of Alaska from oil exploration. The Biden administration announced major restrictions on offshore oil leasing in the Arctic Ocean and across Alaska’s North Slope supposedly to temper criticism from environmentalists over a pending decision on an oil drilling project in Alaska’s National Petroleum Reserve known as Willow and to form a “firewall” to limit future oil leases in the region. The Interior Department said it would issue new rules to block oil and gas leases on more than 55 percent of the 23 million acres

that form the National Petroleum Reserve-Alaska and bar drilling in nearly 3 million acres of the Beaufort Sea — closing it off from oil exploration. The restricted area of over 16 million acres is about the size of West Virginia. The Willow project, if approved, would take place inside the petroleum reserve, which is located about 200 miles north of the Arctic Circle. The National Petroleum Reserve was established in 1912 as a backup source of oil for the federal government, originally for the Navy, as it was at one time referred to as the Naval Petroleum Reserve. Four sites in the country comprised the Naval Petroleum Reserve. The fourth site is on the North Slope of Alaska.

March 16, 2023

145. Sen. Whitehouse introduces the "Clean Competition Act," a carbon border tax. One consequence of this policy would be a negative impact on trade relations with the rest of the world. A carbon border tax will likely lead to retaliatory tariffs with our trading partners and a trade war as increasing tariffs are applied back and forth. A carbon tax like this one would impact heavy industry the most, as it would raise prices on things like steel, aluminum, and other industrial inputs. Because the costs of tariffs are ultimately passed along to consumers, starting a trade war with the world's largest producer of aluminum (China produced nearly 60 percent of world aluminum in 2021) is a far cry from supporting the American working class. Additionally, carbon border taxes are ripe for political gamesmanship because determining the true carbon intensity of products from a variety of countries with different regulatory systems and variations in how emissions are tracked is no simple task. The sheer complexity of rating products would impose massive compliance costs throughout global supply chains, the last thing that is needed with runaway inflation and supply chains that are still

recovering from the dual shocks of the pandemic and Russia's invasion of Ukraine.

March 17, 2023

146. EPA's "Good Neighbor" rule increases the costs of electricity for consumers. The Biden administration announced tougher limits on emissions from power plants, factories and other industrial facilities that cross state boundaries. The new standards, announced by the Environmental Protection Agency (EPA), are intended to place tighter constraints on emissions from 23 Midwestern and Western states that have coal and natural gas power plants and facilities. This interstate regulation, known as the "good neighbor" rule, strengthens and expands an earlier interstate air pollution standard that was enacted during the Obama administration. In finalizing the rule, the EPA included three western states in the regulation — California, Nevada and Utah, due mainly to emissions from their industrial facilities. The new rule includes increased flexibilities, giving power plants emission allowances that will decrease over time. EPA was able to finalize the new standards as the U.S. Court of Appeals for the D.C. Circuit rejected a challenge to EPA's proposed rule by coal companies and others this month. This rule is but one of many the Biden Administration is planning to roll out in pursuit of its quest to kill coal plants in the United States, as IER has detailed.

March 20, 2023

147. Biden uses veto to preserve DOL Rule on ESG investing.

March 23, 2023

148. U.S. Army Corp of Engineers slow walks Line 5 permitting process.

March 30, 2023

149. California gasoline price gouging bill. California Democratic lawmakers approved a bill that could provide a penalty for supposed price gouging at the gasoline pump, allowing regulators the power to fine oil companies for supposedly profiting from gas price spikes similar to those that California experienced last summer. Democratic Governor Gavin Newsom called for a special legislative session to pass a new tax on oil company profits after the average price of gas in California hit a record high of $6.44 per gallon, according to AAA. State regulators, however, did not pass a new tax because they were worried about supply shortages and higher prices as oil companies pass the new tax onto consumers.

March 31, 2023

150. New York State to ban gas stoves in new buildings. New York will become the first state to pass a law banning natural-gas and other fossil-fuel hookups in new buildings on its way to meeting President Biden's net zero carbon goals and the state's own targets for greenhouse-gas reduction. The New York State Climate Leadership and Community Protection Act, passed in 2019, calls for a reduction in economy-wide greenhouse-gas emissions of 40 percent by 2030 and 85 percent by 2050 from 1990 levels.

April 4, 2023

151. The Bureau of Land Management (BLM) proposes a rule to try to get around the Federal Land Policy and Management Act's (FLPMA) requirements for "multiple-use and sustained yield" and instead have even more lands in conservation.

April 12, 2023

152. Biden releases new rules to force electric Vehicles on Americans. The New York Times notes that EPA is releasing rules that are intended to ensure that electric cars represent between 54 and 60 percent of all new cars sold in the United States by 2030 and 64 to 67 percent by 2032—in 9 years. That would exceed President Biden's earlier goal announced in 2021 to have all-electric cars account for half of new car sales by 2030. The purpose of the new EPA regulations is to essentially regulate cars with combustible engines out of business by making the rules so stringent that car companies cannot comply, which is a de facto death knell. Today, less than six percent of cars are electric, despite tax credits of up to $7,500. The federal government is also providing tens of billions of subsidies to the battery producers and offering prime parking spaces to electric vehicles with charging stations at nearly every shopping center in America. This ruling would result in a complete transformation of the automotive industrial base and the automotive market, whether the American public likes it or not.

153. EPA announces new GHG emissions regulations rule for heavy-duty vehicles ((such as delivery trucks, refuse haulers, public utility trucks, transit, shuttle,

school buses, etc.) and tractors (such as day cabs and sleeper cabs on tractor-trailer trucks) starting in model year 2027.

April 25, 2023

154. EPA Proposes to Regulate Carbon Dioxide Emissions from Existing and New Power Plants.

May 12, 2023

155. Department of Transportation Proposes Rules to Reduce Methane Emissions from pipelines.

May 15, 2023

156. EPA proposes new regulations requiring power plants to reduce GHG emissions and require carbon capture and sequestration or hydrogen co-firing even though these are uneconomic technologies.

June 2, 2023

157. Biden orders a 20-year ban on oil and gas leasing within 10 miles of Chaco Culture National Historical Park. In withdrawing the lands from development against the wishes of the Navajo Nation, the action prevents Navajo mineral owners from developing their oil and natural gas resources and realizing $194 million in royalty income over 20 years.

June 22, 2023

158. The U.S. Fish and Wildlife Service (FWS) proposes three new ESA rules regarding interagency cooperation, listings, and critical habitat designation. Taken together, the Biden Administration is seeking to erode the standards with the goal of listing species that do not credibly meet the ESA's definition of threatened or endangered species and designated critical habitat on such massive scales, including areas that are unoccupied. The result is reduced areas open to development, increased costs, unwarranted or unjustified permit requirements, delays, and a multitude of operational constraints that significantly impact the ability to responsibly develop energy resources.

159. The U.S. Fish and Wildlife Service (FWS) along with the National Marine Fisheries Service (NMFS) propose new regulation on interagency cooperation with respect to the Endangered Species Act.

160. The FWS and NMFS also propose the new regulations on Listing Endangered and Threatened Species and Designating Critical Habitat.

161. The FWS proposes an additional rule pertaining to endangered species. These three rules taken together seek to erode the standards with the goal of listing species that do not credibly meet the ESA's definition of threatened or endangered species and designated critical habitat on such massive scales, including areas that are unoccupied. The result is reduced areas open to development, increased costs, unwarranted or unjustified permit requirements, delays, and a multitude of operational constraints that significantly impact the ability to responsibly develop energy resources.

June 30, 2023

162. The U.S. Fish and Wildlife Service (FWS) proposes to list the Dunes Sagebrush Lizard as endangered under the Endangered Species Act (ESA). Despite extensive conservation efforts by oil and natural gas operators, the listing in the highly productive Permian Basin of Texas and New Mexico seems specifically designed to reduce development in one of the nation's most prolific oil producing regions.

July 20, 2023

163. Biden Administration Proposes to Raise Drilling Costs on Federal Lands. The Interior Department's Bureau of Land Management (BLM) has proposed a rule to implement the increased increasing royalty rates for oil and natural gas drilling production on federal lands from 12.5 percent to 16.67 percent—about a third higher–and increased leasing fees that Congress passed in the Inflation Reduction Act (IRA). BLM goes far beyond IRA by also raising the minimum bond paid upon purchasing an individual drilling lease from $10,000 to $150,000. To top it off, they propose raising the minimum bond required for a drilling lease on multiple public lands in a state from $25,000 to $500,000—a 20-fold increase. Developers must pay the bond before drilling begins. The agency also proposes limits designed to steer development away from wildlife and cultural sites. The Interior Department estimates that energy firms will incur $1.8 billion in additional costs by 2031.

July 26, 2023

164. The White House holds a Methane Summit to reduce methane emissions, but doesn't invite anyone from the industry.

July 28, 2023

165. NHTSA proposes new fuel efficiency regulations requiring the average light-duty vehicle estimated to reach 58 miles per gallon by 2032.
166. NHTSA proposes new fuel efficiency regulations for heavy-duty pickup trucks and vans (HDPUVs) for MYs 2030-2035.

August 1, 2023

167. EPA proposes updated greenhouse gas reporting requirements for the oil and natural gas industry. Rather than recognizing that industry continues to decrease methane and other greenhouse gas emissions, the rule attempts to overcount GHGs as a means to eventually impose a carbon budget on the industry. By manipulating emissions factors that are used to calculate emissions, the rule could overestimate industry emissions nearly three-fold.

August 2, 2023

168. The White House issues new guidance on valuing ecosystem services for use in calculating costs and benefits of proposed regulations.

August 3, 2023

169. BLM proposes removing more than 1.6 million acres from oil and gas leasing in Colorado.

August 4, 2023

170. BLM proposes to close 1.566 million acres to oil and natural gas leasing in the Grand Junction and Colorado River Valley field offices in the highly productive Piceance Basin on Colorado's West Slope. The Energy Information Administration (EIA) considers the Piceance Basin to have five of the top 50 natural gas fields in the United States in proven reserves. The update to the Resource Management Plan and supplemental Environmental Impact Statement is designed to cut off new development in the promising Mancos Shale formation.

August 7, 2023

171. Biden proposed 236-pages of revisions to NEPA (National Environmental Policy Act) guidance to make it harder to permit any natural gas, oil, or coal project.

August 10, 2023

172. EPA denies small refinery biofuel waivers and sets large future biofuel mandates.

August 24, 2023

173. The Interior Department holds lease sale 261, but withdraws 6 million acres previously scheduled for leasing.

September 5, 2023

174. The Department of Transportation banned the transportation of LNG by train.

September 6, 2023

175. The Biden administration canceled oil and gas leases held by the state of Alaska in the 1002 area of ANWR. This area was specifically set aside by Congress for oil and gas leasing and Congressionally-mandated lease sales.
176. The Biden administration proposed new regulations to make it more difficult to produce oil and gas in the National Petroleum Reserve-Alaska by withdrawing almost half of the prospective area.

October 2, 2023

177. The Biden administration's five-year plan for offshore oil and gas leasing will not include any sales in 2024 and will feature just three in the final four years–the lowest number of auctions in the history of the program.

178. Army Corps of Engineers continues "inexplicably lethargic" environmental review of Line 5. Line 5 moves about 23 million gallons of oil and gas products daily between the United States and Canada.

October 18, 2023

179. An E&E News analysis shows a 30 percent decrease in permits issued for new offshore oil and gas wells during the first two years of the Biden administration compared to the equivalent period under the Trump administration. Unfavorable policies are deterring companies from making long-term, capital-intensive investments in the U.S. Gulf of Mexico (GOM), where almost all U.S. offshore drilling occurs. The Bureau of Safety and Environmental Enforcement (BSEE) permitted 105 wells in Biden's first two years, which compares to approving 148 during Trump's first two years in office and 275 during Obama's first two years. Oil companies face tougher regulations under Biden, uncertainty in oil prices, and higher expenses as they move into drilling deeper waters.

October 27, 2023

180. A proposed Environmental Protection Agency (EPA) rule on hydrofluoric-acid-based alkylation could spur a round of refinery closures as the cost of replacing hydrofluoric acid based alkylation with alternatives is extremely high. EPA is considering adding amendments to its Risk Management Program (RMP) regulation that could effectively eliminate the use of hydrofluoric acid at U.S. refineries to make cleaner gasoline. Finalization of the rule would result in a loss of U.S. alkylation capacity that would reduce supplies of gasoline and aviation fuel, resulting in higher fuel prices for consumers. It could also shutter some refineries and impact U.S. energy and economic security.

October 31, 2023

181. Biden designates longtime political operative Laura Daniel-Davis as Acting Deputy Secretary for the Department of Interior. Biden previously nominated Daniel-Davis to serve as Assistant Secretary for Land and Minerals Management, but withdrew the nomination after it became clear it would not advance in the senate over concerns of her anti-production track record. This move bypasses congressional authority and places another politically motivated opponent of domestic energy production into the leadership of DOI.

November 2, 2023

182. Biden's Department of Energy (DOE) has increased the time it takes to review a permit for exporting LNG from 7 weeks to a minimum of 11 months. The slowing of permit approval could mean that nearly-completed LNG projects are not able to supply European buyers in need of gas because they do not have the permit. The drastic slowing of LNG export permits represents the most significant limit thus far on an industry planning to add 50 percent more to U.S. export capacity by 2026.

November 6, 2023

183. Biden-Harris Administration Releases Final Guidance on OMB Circular A-4. The 2003 version of Circular A4 advised agencies to use discount rates ranging from 3% to 7% to calculate present values of future costs and benefits. The updated 2023 Circular A4 advises agencies to use the rate of return to Treasury Inflation Protected Securities (TIPS), which currently are roughly 1.7%. The rates reflect the weight given to future impacts of climate change. A higher rate means

a lower dollar value is assigned to future impacts; a lower rate assigns more value to those impacts.

November 11, 2023

184. Biden's Department of the Interior announced a draft of the department's Environmental Justice Strategic Plan. The plan calls for all DOI employees, including those responsible for permitting energy production on federal lands, to be "held accountable for advancing environmental justice." The plan also calls for more of DOI's resources to be used for the purposes of increasing employees' 'awareness and understanding of environmental justice" to be considered in all decision making.

November 17, 2023

185. U.S. Senate Majority Leader Charles Schumer and 22 other Democratic senators recently wrote to the U.S. Federal Trade Commission (FTC), alleging that multi-billion dollar acquisitions by Exxon Mobil and Chevron would lead to reduced competition and higher prices for consumers and asking regulators to launch antitrust probes. Exxon has proposed buying Pioneer Natural Resources for $60 billion and Chevron agreed to acquire Hess for $53 billion. The letter clearly shows, however, that these politicians do not understand much about the U.S. oil market: its players and their contributions to the nation's energy security. First, it is hard to understand how competition would be reduced when Exxon and Pioneer combined produce only about 5 percent of U.S. oil, which is just a fraction of the oil OPEC members control–approximately 80 percent of the world's proven oil reserves. The United States has roughly 9,000 small independent oil producers that produce 83 percent of total U.S. oil production

and 90 percent of total U.S. natural gas production. In Texas, there were more than 5,700 oil and gas producers operating in 2022.

December 1, 2023

186. Buried within the Department of Interior's extensive 200+ page proposal for updating the Fluid Mineral Leases and Leasing Process is a proposed rule that introduces a novel "preference criteria," a potentially transformative mechanism that has garnered relatively little attention but could provide the Biden administration with an additional tool to impede responsible oil and natural gas development. In essence, this would empower the Bureau of Land Management to integrate the "preference criteria" into its regulations governing oil and natural gas, enabling the BLM to preemptively exclude land parcels with "sensitive cultural, wildlife, and recreation resources" from potential leasing, even before conducting environmental analyses.

December 4, 2023

187. EPA issues new methane rule. EPA's new rule requires frequent monitoring and repair of methane leaks at well sites, centralized production facilities, and compressor stations using established inspection technologies or, at an operator's election, novel advanced detection technologies. Similarly, storage vessels at production facilities are regulated in largely the same manner under this final rule as existing VOC requirements. However, storage vessels that previously were unaffected by regulation, including both new and existing facilities, may now be subject to NSPS based upon updated definitions and the addition of a new applicability trigger. Finally, the rule aims to phase out venting and flaring of gas coming from oil wells.

December 8, 2023

188. The Environmental Protection Agency (EPA) updated its estimate of the "social cost" of carbon dioxide—a contrived way of increasing the cost of everything made from or using hydrocarbon resources to vilify those projects and keep them from becoming economic. The new estimate nearly quadruples the estimated cost of carbon dioxide to the world that the Biden administration is currently using — a change that will result in stronger climate rules and more stringent regulations that will increase costs for consumers as the least expensive materials will now cost more when projects are being considered and their costs estimated. The change could affect everything from "tiny rules" such as those concerning vending machines to more significant regulations. It is the Biden administration's way to justify its present position, which as President Biden said, is to "end fossil fuels."

December 11, 2023

189. The Interior Department announced new actions in support of "nature-based" solutions. The policy directs land managers and decision makers to use guidance from "environmental justice and Indigenous Knowledge" to implement "nature-based" climate solutions into all operations on federal lands.

December 14, 2024

190. The U.S. Treasury Department's Office of the Comptroller of the Currency (OCC) carried out its first climate risk assessment of more than two dozen banks in recent months, laying the groundwork for heightened scrutiny of Wall Street's

accounting for climate change. The climate risk assessment will limit financing opportunities for oil and gas projects.

January 5, 2024

191. The Department of the Interior announces Deputy Assistant Secretary for Land and Minerals Management Steve Feldgus has been named Principal Deputy Assistant Secretary for Land and Minerals Management. Feldgus has been an outspoken opponent of domestic mineral production.

January 12, 2024

192. The Biden administration revealed its strategy for implementing a new methane emissions fee targeting the oil and gas sector, aimed at accelerating efforts to curb the release of this potent greenhouse gas. This fee, reaching up to $1,500 per metric ton by 2026, was stipulated by Congress under the 2022 Inflation Reduction Act. However, crucial aspects such as the calculation method for charges and criteria for exemptions have been delegated to the EPA for determination.

January 26, 2024

193. Biden halts permitting for new LNG export facilities.

January 31, 2024

194. Interior halts New Mexico oil plan.

February 7, 2024

195. A new round of political appointments at the Department of Energy places Alexandra Teitz in the office of the DOE's general council. Teitz, a former Obama administration staffer, has written extensively about the federal government's responsibility to prohibit the development of natural gas and oil on federal lands during her work with Climate 21.

February 9, 2024

196. A new round of political appointments at the Department of the Interior places Maryam Hassanein in the office of the DOI's Land and Minerals Management. Prior to joining the administration, Hassanein worked for the League of Conservation Voters, an extreme environmentalist organization that promotes stopping energy production on federal lands in the name of the "climate crisis" among other radical environmental positions.

February 14, 2024

197. The Environmental Protection Agency recently finalized a new rule to reduce the level of particulate matter (PM) by updating the national air-quality standards. Particulate matter is made up of microscopic solid particles such as dirt, soot or smoke and liquid droplets in the air up to 2.5 microns in diameter — far smaller than a human hair. Particulate matter comes from a variety of sources including power plants, cars, dust, construction sites and wildfire smoke. The new rule will lower the annual standard to 9 micrograms per cubic meter from 12 micrograms per cubic meter established by the Obama Administration. The 24-hour standard which is meant to account for short-term spikes will remain at 35 micrograms

per cubic meter. Since 2000, particulate matter has declined by 42 percent, even as the U.S. gross domestic product has increased by 52 percent. The new rule does not impose controls on specific industries; it lowers the annual standard for fine particulate matter for overall air quality, leaving states to force industries to comply or close their doors. The EPA plans to take samples of air across the country starting this year through 2026 to identify counties and other areas that do not meet the new standard. It will also tweak its air monitoring network to better capture the air pollution that communities living near industrial infrastructure face. States would then have 18 months to develop compliance plans for those areas. States that do not meet the new standard by 2032 could face penalties. While the standard itself would not force polluters to shut down, the EPA and state regulators could use it as the basis for other rules that target specific sources such as diesel-fueled trucks, refineries and power plants. Opponents indicate that it will hamper American manufacturing and eliminate jobs and could shut down power plants and/or refineries. EPA officials, however, did not estimate the employment impact of the new rule because of the variety of industries affected. Industry groups like the American Forest & Paper Association, American Wood Council and the group's member company CEOs sent a letter to the White House in October expressing their opposition to the rule, saying the move, "threatens U.S. competitiveness and modernization projects in the U.S. paper and wood products industry and in other manufacturing sectors across our country." "This would severely undermine President Biden's promise to grow and reshore U.S. manufacturing jobs, and ultimately make American manufacturing less competitive." "It also would harm an industry that has been recognized as an important contributor to achieving the Administration's carbon reduction goals, including in future procurement for federal buildings."

198. The Department of Energy announces its second annual equity action plan. Straying ever farther from the department's statutory mission to "assist in the development of a coordinated national energy policy," Secretary Granholm seeks to prioritize "environmental justice and inclusivity" in the agency's rulemaking. The plan complicates DOE procurement and R&D processes by introducing arbitrary political considerations.

March 6, 2024

199. SEC approves climate disclosure rule forcing public companies to report their greenhouse gas emissions and climate risks.

March 7, 2024

200. John Podesta starts his first day as Biden's "global climate boss."

From: Christopher Rager
To: Reiten, John R.; Beehler, Jace
Subject: RE: API Follow Up
Date: Monday, June 17, 2024 3:08:01 PM
Attachments: image001.png

Thanks John. That works.

Best,

Chris

From: Reiten, John R. <jreiten@nd.gov>
Sent: Monday, June 17, 2024 4:05 PM
To: Christopher Rager <RagerC@api.org>; Beehler, Jace <jabeehler@nd.gov>
Subject: RE: API Follow Up

Yes- Happy to!

How does Wednesday at 10 am CST work for you?

John

From: Christopher Rager <RagerC@api.org>
Sent: Monday, June 17, 2024 8:03 AM
To: Beehler, Jace <jabeehler@nd.gov>
Cc: Reiten, John R. <jreiten@nd.gov>
Subject: RE: API Follow Up

Jace,

Good morning. No problem at all. Appreciate your time on this.

John,

Good to meet you via email. Would you have any availability this week to discuss our September Summit?

Best,

Chris

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Monday, June 17, 2024 1:47 AM
To: Christopher Rager <RagerC@api.org>
Cc: Reiten, John R. <jreiten@nd.gov>
Subject: Re: API Follow Up

My apologies for the delay.

Can I have my colleague John Reiten get in touch with you to learn more about the Summit and the potential role the Governor would play?

Thank you,
Jace

From: Christopher Rager <RagerC@api.org>
Sent: Friday, June 14, 2024 7:40 AM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: FW: API Follow Up

Jace,

Good morning – Happy Friday. Wanted to see if you had a chance to review my below note?

Have a great weekend!!

Chris

From: Christopher Rager
Sent: Monday, June 10, 2024 10:12 AM
To: jabeehler@nd.gov
Subject: API Follow Up

Jace,

Good morning. Great seeing you last week at RGA in New Orleans. Per our conversation, wanted to see if you have some time this week to discuss Governor Burgum's possible participation in our September 25th – 26th State Government Relations Summit?

Best,

Chris

Christopher L. Rager
Director, State Government Relations
American Petroleum Institute
o: 202.682.8389
m: 571-328-6791

www.api.org

signature_1982813188

From: Ron Ness
To: Haase, Reice; Reiten, John R.
Subject: FW: NDPC Bakken Power Supply Work Group
Date: Monday, March 4, 2024 4:38:57 PM
Attachments: image001.jpg

FYI – Claire says you guys have this on the radar.

From: Ron Ness <ronness@ndoil.org>
Sent: Monday, March 4, 2024 4:30 PM
To: Ron Ness <ronness@ndoil.org>
Cc: Eric Delzer <edelzer@ndoil.org>; Bradley A. Aman <brad.aman@clr.com>
Subject: NDPC Bakken Power Supply Work Group

At the recent NDPC Board of Directors meeting, NDPC Chairman of Board Todd Slawson created a work group to explore the growing challenges in the Bakken Region relating to reliable and affordable electric power. Chairman Slawson appointed Bradley Aman, Vice President of Facilities and Projects for Continental Resources as Chairman of the work group. The work group will educate themselves on the power supply/power demand issues and identify potential solutions for oil and gas producers and midstream companies. The intent of the work group is to hold a handful of meetings and bring forth their findings to the NDPC Summer Board meeting on June 19th in Medora.

The Bakken Power Supply Work Group will hold the first virtual or in-person meeting on Thursday, March 14 from 3:30 – 5pm. Todd Brickhouse the CEO at Basin Electric Power Cooperative will attend the meeting and provide an overview from Basin's perspective on power supply to the Bakken Region.

If you or your company would like to have a representative or two on the Work Group contact Eric Delzer to be added to the list by March 12th. [redacted]

Details and an agenda for the meeting will be sent on March 13th.

Please contact me with any questions.

Ron Ness
President
North Dakota Petroleum Council

NORTH DAKOTA
PETROLEUM
FOUNDATION

BAKKEN ROCKS

COOKFEST

18TH JULY

TIOGA, ND

FREE
FOOD
LIVE
MUSIC
& more

2:30-4 PM

BAKKEN BASICS EDUCATION SESSION
TIOGA COMMUNITY CENTER
410 6th Street NE

4-7 PM

BBQ, MUSIC BY BILL FALCON & THE GOOD MEDICINE BAND, & MORE!
TIOGA PARK
5th Street NE

VISIT NDPETROLEUMFOUNDATION.ORG/COOKFEST FOR MORE INFO

From:	Tessa Sandstrom
To:	ND Petroleum Foundation
Subject:	Join us for the Bakken Rocks CookFest on July 18 in Tioga!
Date:	Wednesday, June 12, 2024 3:21:53 PM
Attachments:	2024 CookFest Poster.pdf

Good afternoon!

The North Dakota Petroleum Foundation will be hosting this year’s Bakken Rocks CookFest in Tioga on Thursday, July 18 in Tioga. The event includes a Bakken Basics Information Session from 2:30-4 p.m. in the Tioga Community Center and a BBQ, Education Tent, live music, games and activities for kids, and more from 4-7 p.m. in the Tioga Park.

This free, family-friendly event has been an important outreach event for the Foundation and the oil and gas industry. This year, we’re expecting anywhere between 2,500 and 3,500 people to attend this year’s event, and hope you will join us to meet with constituents and enjoy a great evening!

We appreciate your support in the past and we hope to see you at this year’s event!

Sincerely,

TESSA SANDSTROM
Executive Director
NORTH DAKOTA PETROLEUM FOUNDATION

O: 701.557.3972

www.NDPetroleumFoundation.org | www.NDOil.org

From: Eric Delzer
To: Reiten, John R.; Haase, Reice
Cc: Helms, Lynn D.; Jonathan Fortner
Subject: Fw: EPA Highlights Biden-Harris Administration’s New National Security Memorandum on Critical Infrastructure
Date: Tuesday, April 30, 2024 4:52:46 PM
Attachments: Outlook-zhrlqwb5.png

John and Reice,

Take a look at the press release below regarding the President's national security memorandum to secure and enhance the resilience of critical U.S. infrastructure that came out this afternoon. This would be a great opportunity for the NDIC to call out the disingenuous irony of this proclamation in a press statement or letter. Especially since they're literally forcing us to go to war with them to protect our critical infrastructure.

National Security Memorandum on Critical Infrastructure Security and Resilience | The White House

NATIONAL SECURITY MEMORANDUM/NSM-22
MEMORANDUM FOR THE VICE
PRESIDENT THE SECRETARY OF
STATE THE SECRETARY OF THE
TREASURY THE SECRETARY OF
DEFENSE THE ATTORNEY

www.whitehouse.gov

Biden is directing all agencies to protect our nation's critical infrastructure, but the bureaucrats running those agencies at the direction of the administration are currently the biggest threat to our nation's critical infrastructure. They're trying to shut down pipelines and coal plants at the same time forcing EV's and grid batteries that rely on Chinese supply chains, and in some cases, software created by Chinese companies, when our biggest cybersecurity threat is coming from China. Among the critical infrastructure directly identified in this memorandum are Energy, Food and Agriculture, Transportation Systems, and Water and Wastewater Systems. All of these sectors have already been severely compromised by their own actions. There is a ton of great material in here you can throw back in their face.

The term “critical infrastructure” has the meaning provided in section 1016(e) of the

USA Patriot Act of 2001 (42 U.S.C. 5195c(e)), namely systems and assets, whether physical or virtual, so vital to the United States that the incapacity or destruction of such systems and assets would have a debilitating impact on national security, national economic security, national public health or safety, or any combination of those matters.

The term "all threats, all hazards" means a threat or an incident, natural or manmade, that warrants action to protect life, property, the environment, and public health or safety, and to minimize disruptions of Government, social, or economic activities. It includes, but is not limited to: natural disasters, cyber incidents, industrial accidents, pandemics, acts of terrorism, sabotage, supply chain disruptions to degrade critical infrastructure, and disruptive or destructive activity targeting critical infrastructure.

The term "resilience" means the ability to prepare for threats and hazards, adapt to changing conditions, and withstand and recover rapidly from adverse conditions and disruptions.

Some of these directives directly contradict their own actions:

"The Department of Energy (DOE) shall carry out its statutory responsibilities to address the short-, mid-, and long-term energy challenges facing the Nation, including those implicating electricity, petroleum, natural gas, nuclear material, and other energy resources and services, in coordination with relevant Federal departments and agencies, as appropriate. Consistent with authorities, DOE leads the policy, preparedness, risk analysis, technical assistance, research and development, operational collaboration, and emergency response activities for the United States energy sector."

"The Federal Government, including SRMAs, shall use a common risk-based approach to reducing risk to critical infrastructure. Critical infrastructure risks can be assessed in terms of threats or hazards, vulnerability, and consequence. For the purposes of this effort, the term "risk" refers to the potential for an unwanted outcome, as determined by its likelihood and the consequences. Risk management efforts should be prioritized based on this shared definition, which necessitates identifying the criticality of assets and systems within and across sectors."

"Critical infrastructure owners and operators have primary responsibility, and are uniquely positioned, to manage most risks to their operations and assets. The policy of the Federal Government shall be to support and guide the entities that own, operate, or otherwise control critical infrastructure assets and systems by providing these entities with the information, intelligence analysis, and other support, as appropriate, to manage and mitigate asset-level risks."

"Effective risk management necessitates the Federal Government, in coordination with

owners and operators to the extent practicable, identify, assess, prioritize, mitigate, and monitor risks that may have a potentially debilitating impact on national security (including national defense and continuity of Government), national economic security, or public health or safety."

"Departments and agencies shall also collaborate with private-sector partners; State, local, Tribal, and territorial entities"

"This effort shall include supporting sector coordinating councils, including the State, Local, Tribal, and Territorial Government Coordinating Council. These councils should be inclusive and include owners and operators, their trade associations, and other industry representatives."

The memo mostly targets cyber security threats, but the biggest threat to critical infrastructure in the U.S. is the Biden administration itself.

We'd be happy to support NDIC's leadership in any collaborative response. I'm guessing all other trade associations in the state would be willing to sign on as well if you wanted to include them. I know you guys are as swamped as we are, but the timing of this couldn't be more perfect. Especially, since it was literally published while the NDIC was holding a public meeting discussing all these impending federal rules and lawsuits.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: EPA Press Office <noreply@epa.mediaroom.com>
Sent: Tuesday, April 30, 2024 3:03 PM
To: Eric Delzer <edelzer@ndoil.org>
Subject: EPA Highlights Biden-Harris Administration’s New National Security Memorandum on Critical Infrastructure

Issued: Apr 30, 2024 (3:15pm EDT)
If you wish to unsubscribe please do so here: https://epa.mediaroom.com/index.php?

s=20300&unsub=1&hide_page_content=1

EPA Highlights Biden-Harris Administration’s New National Security Memorandum on Critical Infrastructure

EPA takes important steps to secure our nation’s water infrastructure

WASHINGTON – Today, April 30, 2024, the White House issued a new National Security Memorandum (NSM) to secure and enhance the resilience of U.S. critical infrastructure. The NSM will replace a decade-old presidential policy document on critical infrastructure protection and launch a comprehensive effort to protect U.S. infrastructure against all threats and hazards, current and future.

“Cybersecurity and climate change threats pose serious risks to the drinking water and wastewater services that people in this country rely on every day, and recent cyber attacks on water systems underscore the urgency of increased and coordinated action to protect public health and the environment,” **said EPA Deputy Administrator Janet McCabe.** “The Biden-Harris Administration is leading a comprehensive effort to secure our nation’s critical infrastructure against all threats, and the efforts outlined in the new National Security Memorandum are vital to ensuring that EPA and other federal entities are taking the necessary steps to safeguard public health and our economy.”

The NSM will help ensure U.S. critical infrastructure can provide the nation a strong and innovative economy, protect American families, and enhance our collective resilience to disasters before they happen – strengthening the nation for generations to come. This NSM specifically clarifies the roles and responsibilities of the lead federal agencies identified to improve the resilience of our critical infrastructure sectors against all hazards. EPA is the official sector risk management agency with respect to the water sector. The NSM also implements a coordinated national approach to assess and manage sector-specific risks.

Thanks to the President’s Investing in America agenda, as well as the emergence of new technologies, America has a historic opportunity to build for the future. Good investments require taking steps to manage risk, and for our water infrastructure, that means building in resilience to all hazards upfront and by-design. Through the President’s Investing in America agenda, the Biden-Harris Administration has announced nearly $50 billion to modernize the nation’s water infrastructure. These resources, including more than $23 billion in drinking water and clean water State Revolving Funds, can be used to support a broad range of approaches to build resilience to all hazards, including climate resilience and cybersecurity threats.

The nation faces an era of strategic competition where state actors will continue to target American critical infrastructure – and tolerate or enable malicious activity conducted by non-state actors. In the event of crisis or conflict, America’s adversaries may attempt to compromise our critical infrastructure to undermine the will of the American public and impede the projection of U.S. military power abroad. Resilience, particularly for our most sensitive assets and systems, is the cornerstone of homeland defense and security.

Further, the growing impact of climate change, including changes to the frequency and intensity of natural hazards, as well as supply chain shocks and the potential for instability, conflict, or mass displacement, places strain on the infrastructure that

Americans depend upon to live and do business.
National Security Memorandum
2023 National Intelligence Strategy
EPA Cybersecurity for the Water Sector
For further information: EPA Press Office (press@epa.gov)

From: Eric Delzer
To: Reiten, John R.
Cc: Norrell, Ryan
Subject: RE: DAPL DEIS Press Release and letter from 30 Members of Congress to the USACE
Date: Thursday, January 18, 2024 3:10:11 PM
Attachments: image001.png

Thanks for sharing John.

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Thursday, January 18, 2024 2:40 PM
To: Reiten, John R. <jreiten@nd.gov>
Cc: Norrell, Ryan <ryan.norrell@nd.gov>
Subject: DAPL DEIS Press Release and letter from 30 Members of Congress to the USACE

Please see the following link for a press release and the attached letter to the USACE:

30-some members of Congress sent to the US Army Corps today expressing concern with a draft environmental impact statement and climate analysis the agency has prepared for the Dakota Access Pipeline and its Lake Oahe crossing.

https://www.merkley.senate.gov/merkley-grijalva-colleagues-call-to-center-environmental-justice-and-climate-impacts-of-the-dakota-access-pipeline-increase-transparency-and-tribal-consultation-in-final-environmental-impact-statem/

John Reiten

From: Eric Delzer
To: Reiten, John R.
Subject: Re: [FR] Documents from Land Management Bureau
Date: Wednesday, April 10, 2024 1:15:57 PM
Attachments: Outlook-qsfrrl35.png

Thanks John. I did see that this morning. The governor did great this morning too. Give him our thanks for laying it out so clearly. We appreciate his leadership on this.

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Wednesday, April 10, 2024 7:34 AM
To: Eric Delzer <edelzer@ndoil.org>
Subject: FW: [FR] Documents from Land Management Bureau

From: Federal Register Subscriptions <subscriptions@mail.federalregister.gov>
Sent: Wednesday, April 10, 2024 3:11 AM
To: Reiten, John R. <jreiten@nd.gov>
Subject: [FR] Documents from Land Management Bureau

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Documents from Land Management Bureau

MATCHING DOCUMENTS

Land Management Bureau

Rules

Waste Prevention, Production Subject to Royalties, and Resource Conservation

FR Document: 2024-06827 PDF Pages 25378-25432 *(55 pages)*
Citation: 89 FR 25378 Permalink

Abstract: On November 30, 2022, the Department of the Interior, through the Bureau of

Land Management (BLM), published in the Federal Register a proposed rule entitled "Waste Prevention, Production Subject to Royalties, and Resource Conservation." This final rule aims to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production activities on Federal and Indian leases. The final rule also ensures that, when Federal or Indian gas is wasted, the public and Indian...

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From: Eric Delzer
To: Reiten, John R.
Cc: Brady Pelton
Subject: Fw: [FR] Documents from Interior Department and whose Associated Unified Agenda Deemed Significant Under EO 12866
Date: Friday, April 5, 2024 9:43:57 AM
Attachments: Outlook-pygh1ccl.png

Good morning John,

It looks like the three endangered species USFWS final rules came out this morning. Please see the FR notices below.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Federal Register Subscriptions <subscriptions@mail.federalregister.gov>
Sent: Friday, April 5, 2024 3:20 AM
To: Eric Delzer <edelzer@ndoil.org>
Subject: [FR] Documents from Interior Department and whose Associated Unified Agenda Deemed Significant Under EO 12866

subscription results for Friday, April 5th, 2024 *3 matching documents*

Documents from Interior Department and whose Associated Unified Agenda Deemed Significant Under EO 12866

MATCHING DOCUMENTS

Fish and Wildlife Service

Rules

Endangered and Threatened Species:

Interagency Cooperation

FR Document: 2024-06902 PDF Pages 24268-24298 *(31 pages)*
Citation: 89 FR 24268 Permalink

Abstract: FWS and NMFS (collectively referred to as the "Services" or "we") finalize revisions portions of our regulations that implement section 7 of the Endangered Species Act of 1973, as amended ("Act"). The revisions to the regulations clarify, interpret, and implement portions of th Act concerning the interagency cooperation procedures.

Listing and Designating Critical Habitat

FR Document: 2024-06899 PDF Pages 24300-24335 *(36 pages)*
Citation: 89 FR 24300 Permalink

Abstract: We, the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS; collectively, the "Services"), finalize revisions to portions of our regulations tha implement section 4 of the Endangered Species Act of 1973, as amended. The revisions to the regulations clarify, interpret, and implement portions of the Act concerning the procedures and criteria used for listing, reclassifying, and delisting species on the Lists of Endangered and Threatened Wildlife and Plants...

Regulations Pertaining to Endangered and Threatened Wildlife and Plants

FR Document: 2024-06901 PDF Pages 23919-23941 *(23 pages)*
Citation: 89 FR 23919 Permalink

Abstract: We, the U.S. Fish and Wildlife Service (Service), revise our regulations concerning protections of endangered species and threatened species under the Endangered Species Act (Act or ESA). We reinstate the general application of the "blanket rule" option for protecting nev listed threatened species pursuant to section 4(d) of the Act, with the continued option to promulgate species-specific section 4(d) rules. We also extend to federally recognized Tribes tl exceptions to prohibitions for...

National Oceanic and Atmospheric Administration

Rules

Endangered and Threatened Species:

Interagency Cooperation

FR Document: 2024-06902 PDF Pages 24268-24298 *(31 pages)*
Citation: 89 FR 24268 Permalink

Abstract: FWS and NMFS (collectively referred to as the "Services" or "we") finalize revisions portions of our regulations that implement section 7 of the Endangered Species Act of 1973, as amended ("Act"). The revisions to the regulations clarify, interpret, and implement portions of th Act concerning the interagency cooperation procedures.

Listing and Designating Critical Habitat

FR Document: 2024-06899 PDF Pages 24300-24335 *(36 pages)*
Citation: 89 FR 24300 Permalink

Abstract: We, the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS; collectively, the "Services"), finalize revisions to portions of our regulations tha implement section 4 of the Endangered Species Act of 1973, as amended. The revisions to the regulations clarify, interpret, and implement portions of the Act concerning the procedures and criteria used for listing, reclassifying, and delisting species on the Lists of Endangered and Threatened Wildlife and Plants...

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From: Eric Delzer
To: Reiten, John R.; Brady Pelton; Jonathan Fortner; Bohrer, Jason; Ron Ness
Subject: Re: My updated list of Federal Tracking rules as of 3/11/24
Date: Monday, March 11, 2024 2:32:50 PM
Attachments: image001.png
Outlook-kgrogped.png

Ok, that is the last I heard on my end. I just wanted to make sure I didn't miss anything. Thanks for the update.

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Monday, March 11, 2024 2:28 PM
To: Eric Delzer <edelzer@ndoil.org>; Brady Pelton <bpelton@ndoil.org>; Jonathan Fortner <JonathanFortner@lignite.com>; Bohrer, Jason <jasonbohrer@lignite.com>; Ron Ness <ronness@ndoil.org>
Subject: RE: My updated list of Federal Tracking rules as of 3/11/24

I am working on an MOU between the state and the FS on how we will move forward.

No other major updates. I believe some counites are also working on MOUs?

John

From: Eric Delzer <edelzer@ndoil.org>
Sent: Monday, March 11, 2024 2:26 PM
To: Reiten, John R. <jreiten@nd.gov>; Brady Pelton <bpelton@ndoil.org>; Jonathan Fortner <JonathanFortner@lignite.com>; Bohrer, Jason <jasonbohrer@lignite.com>; Ron Ness <ronness@ndoil.org>
Subject: Re: My updated list of Federal Tracking rules as of 3/11/24

Thanks John. I can't think of any you missed. I do have a question though. Have you heard any updates on the Travel Management Plan or when that process will officially kickoff?

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395

Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Monday, March 11, 2024 2:12 PM
To: Brady Pelton <bpelton@ndoil.org>; Jonathan Fortner <JonathanFortner@lignite.com>; Eric Delzer <edelzer@ndoil.org>; Bohrer, Jason <jasonbohrer@lignite.com>; Ron Ness <ronness@ndoil.org>
Subject: My updated list of Federal Tracking rules as of 3/11/24

Please let me know if I am missing anything!

Federal Rule	Regulatory Agency
Executive Order 13990	Office of the President
North Dakota Resource Management Plan	BLM
Mercury and Air Toxics Standards (MATS)	EPA
Greenhouse Gas // Carbon Rule 2.0	EPA
Gas Pipeline Safety	PHMSA
Endangered Species Act Rule 1, 2, 3	FWS
Mineral Leases and Leasing Process	BLM
NEPA Revisions Phase 2	CEQ
Air Emissions Reporting Requirements	EPA
Conservation and Landscape Health	BLM
National Highway System- GHG Emissions	FHWA
DAPL DEIS	USACE
Natural Asset Companies	SEC
Applicability of Emergency Exemptions	FMCSA
Travel Management Plan	DPG
OOOO Administrative Rule (SIP)	EPA
OOOO (B) & (C) Methane Rule	EPA
Regional Haze	EPA
Coal Combustion Residuals North Dakota Primacy	EPA
Coal Combustion Residuals Legacy Rule	EPA
Minnesota Carbon Free Rule	MNPUC
Waste Emissions Charge for Petroleum and Natural Gas Systems	EPA
Particulate Matter (PM) 2.5	EPA
Tribal Water Reserved Rights	EPA
Baseline Water Quality Standards	EPA
Reporting Requirements for Emissions from Animal Waste	EPA
Waters of the United States	EPA
Chlorpyriphos	EPA
SEC Greenhouse Gas Reporting Rule	SEC
Procedures To Implement the Principles, Requirements, and Guidelines for Federal Investments in Water Resources	USACE
BLM Venting and Flaring	BLM
Climate Disclosure Rule	SEC

NORTH DAKOTA
PETROLEUM
COUNCIL
100 West Broadway, Ste. 200 | P.O. Box 1395 | Bismarck, ND 58501-1395
701.223.6380 | ndpc@ndoil.org | www.NDOil.org

October 6, 2022

The Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency
EPA Docket Center – Air and Radiation Docket
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

ATTN: Jennifer Bohman – submitted via www.regulations.gov

Re: Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Docket Id. No. EPA–HQ–OAR–2019–0424

Dear Administrator Regan:

The North Dakota Petroleum Council (NDPC) appreciates the opportunity to submit comments as your agency considers a proposal to amend specific provisions in the Greenhouse Gas Reporting Rule.

Established in 1952, the NDPC is a trade association that represents more than 550 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline, transportation, mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky Mountain Region.

NDPC members have a vested interest in the Environmental Protection Agency's (EPA) efforts to improve the data collected under the rule and clarify provisions that reporting entities have had questions about. However, we believe some improvements can be made to this proposal.

NDPC specifically endorses the comments submitted on the proposal by the American Exploration and Production Council (AXPC) and the American Petroleum Institute (API). NDPC also submits the following comments for consideration.

Consider Economic Impacts

In 2021, oil and natural gas accounted for 68% of energy consumption in the US.[1] The oil and natural gas industry is an integral part of the US economy and affordable energy benefits all Americans. Cost-effective and balanced regulation of the energy industry can benefit human health and the environment, but economic impacts must always be considered. In recent years we have seen how high energy costs have driven inflation, increasing the cost of essential goods and services for families across all social and economic groups.

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[1] https://www.eia.gov/energyexplained/us-energy-facts/

We understand that the original intent of the rule was to assess significant sources of GHG emissions for potential new regulations, and now it is moving in the direction of estimating all GHG and methane emissions for fee collection. For this reason, the NDPC requests the EPA take great care in finalizing this proposal. Any final rule will directly impact our industry resulting in immediate economic impacts today and on future generations.

Clarify Source Categories

One clarification we feel is necessary is to ensure the oil and natural gas source category and its segments are clearly defined, especially the Processing segment. In the NSPS OOOOa Background Technical Support Document (TSD), the EPA states: "The final rule covers emission sources within the oil and natural gas source category, which includes onshore crude oil production and natural gas production, processing, transmission and storage."

These are discreet segments that the EPA discusses and defines in the TSD. The production segment includes everything from the wellhead through the gathering system and ends at the refinery or natural gas processing plant. The EPA describes oil refining and natural gas processing as: "The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector."

The EPA states further: "Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce 'pipeline quality' dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment." At this point, the pipeline quality natural gas leaves the processing segment and enters the transmission and storage segment.

We are asking the EPA to clarify that while some processing of natural gas can occur in either the production or processing segment, a natural gas processing plant can only exist in the Processing segment, beginning at the end of the gathering system and ending when pipeline-quality natural gas is delivered into the transmission and storage segment.

We appreciate your serious consideration of these comments and appreciate you moving forward in a measured and thoughtful manner.

Sincerely,

Ron Ness
President, North Dakota Petroleum Council

From: Eric Delzer
To: Reiten, John R.
Cc: Brady Pelton
Subject: New GHG Reporting Final Rule
Date: Monday, April 8, 2024 2:36:03 PM
Attachments: Outlook-vavt1zhf.png
GHG Reporting_NDPC Comments_Oct 6, 2022.docx

John,

Just want to give you a heads up on another final rule that is about to come out. It was signed for publishing in the Federal Register last week.

Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule (epa.gov)

This rule was proposed in the summer of 2022. As of right now it has not been published, nor announced yet. I imagine it will drop sometime this week.

ENVIRONMENTAL PROTECTION AGENCY
40 CFR Parts 9 and 98
[EPA-HQ-OAR-2019-0424; FRL-7230-01-OAR]
RIN 2060-AU35
Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule
AGENCY: Environmental Protection Agency (EPA).
ACTION: Final rule.

SUMMARY: The EPA is amending specific provisions in the Greenhouse Gas Reporting Rule to improve data quality and consistency. This action updates the General Provisions to reflect revised global warming potentials; expands reporting to additional sectors; improves the calculation, recordkeeping, and reporting requirements by updating existing methodologies; improves data verifications; and provides for collection of additional data to better inform and be relevant to a wide variety of Clean Air Act provisions that the EPA carries out. This action adds greenhouse gas monitoring and reporting for five source categories including coke calcining; ceramics manufacturing; calcium carbide production; caprolactam, glyoxal, and glyoxylic acid production; and facilities conducting geologic sequestration of carbon dioxide with enhanced oil recovery. These revisions also include changes that will improve implementation of the rule such as updates to applicability estimation methodologies, simplifying calculation and monitoring methodologies, streamlining recordkeeping and reporting, and other minor technical corrections This

Federal Register Notice was signed on April 3, 2024, and the Agency is submitting it for publication in the Federal Register. While we have taken steps to ensure the accuracy of this Internet version of the document, it is not the official version. Please refer to the official version in a forthcoming Federal Register publication, which will appear on the Government Printing Office's website (https://www.govinfo.gov/app/collection/fr) and on Regulations.gov (https://www.regulations.gov) in Docket No. EPA-HQ-OAR-2019-0424. Once the official version of this document is published in the Federal Register, this version will be removed from the Internet and replaced with a link to the official version. or clarifications. This action also establishes and amends confidentiality determinations for the reporting of certain data elements to be added or substantially revised in these amendments.

DATES: This rule is effective January 1, 2025. The incorporation by reference of certain material listed in this final rule is approved by the Director of the Federal Register beginning January 1, 2025. The incorporation by reference of certain other material listed in the rule was approved by the Director of the Federal Register as of January 1, 2018.

I'll let you know if I see it come out.

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

NDPC Board of Directors Meeting February 2024 – Grand Forks, ND

**Times are subject to change*

Important Addresses:

Canad Inn – 1000 S 42nd St, Grand Forks, ND 58201

Energy and Environmental Research Center (EERC) – 15 N 23rd St, Grand Forks, ND 58202

Toasted Frog – 124 N 3rd St, Grand Forks, ND 58203

Ralph Engelstad Arena – One Ralph Engelstad Arena Dr, Grand Forks, ND 58203

Tentative Agenda:

Thursday, February 29th

1:00 – 2:30 p.m.	NDPF Board Meeting
3:00 p.m.	Hotel check-in open
3:00 – 4:30 p.m.	"Best of EERC" Presentation

Please join the NDPC Board of Directors, state and local leaders, and special guests for a dynamic 90-minute session exploring the EERC's current projects that hold significance for our members, state, and region.

6:00 p.m.	Board bus to Toasted Frog
7:00 p.m.	NDPC Board Dinner at Toasted Frog

*Transportation provided to and from Toasted Frog

Friday, March 1st

8:00 a.m.	Board Breakfast, EERC
8:30 – 11:30 a.m.	NDPC Board of Directors Meeting
12:00 p.m.	Lunch/Ticket handout
1:30 – 3:00 p.m.	UND EERC or UND CEM tour
4:30 – 6:00 p.m.	Social at Upper Playmakers (at Canad Inn)
6:00 p.m.	Bus departs for Ralph Engelstad
7:07 p.m.	Puck drop for UND vs. Western Michigan
9:45 p.m.	Bus back to Canad Inn

Check out by 11:00 a.m. Saturday March 2nd

***Thank you to AE2S, Construction Engineers, EERC, & UND Alumni Association & Foundation for hosting our Board of Directors for the UND Hockey game and providing the food and refreshments!!

From: Micaela Rud
To: Reiten, John R.
Cc: Brady Pelton
Subject: NDPC Grand Forks Itinerary
Date: Thursday, February 22, 2024 2:03:26 PM
Attachments: NDPC & UND EERC General Itinerary.pdf

Hi John,

Please see the attachment for our itinerary next week. If you would like to attend the hockey game on Friday, March 1st, please click on this link to RSVP for the social and game. You are certainly welcomed at both! Please let us know if you need anything else.

Thank you!

Micaela Rud
Executive Assistant
North Dakota Petroleum Council
General: 701-223-6380
Direct: 701-204-7345
mrud@ndoil.org

OFFICE OF AIR AND RADIATION
WASHINGTON, D.C. 20460

May 6, 2024

Ms. Holly Hopkins
Vice President, Upstream Policy
American Petroleum Institute
Via Electronic Mail: hopkinsh@api.org

Ms. Wendy Kirchoff
Vice President of Policy and Regulatory Affairs
American Exploration and Production Council
Via Electronic Mail: wendy.kirchoff@axpc.org

Dear Ms. Hopkins and Ms. Kirchoff:

This letter concerns the petition for reconsideration of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (89 FR 16820, March 8, 2024) that you submitted on April 5, 2024, pursuant to Clean Air Act (CAA) section 307(d)(7)(B) on behalf of your respective organizations, American Petroleum Institute and American Exploration and Production Council.

Two of the issues you raise in your petition are the (1) vent gas net heating value (NHV) monitoring and alternate sampling demonstration requirements for flares and enclosed combustion devices, and (2) temporary flaring provisions for associated gas in certain situations.

Without making a determination as to whether these two issues meet the mandatory requirements for reconsideration under CAA section 307(d)(7)(B), the U.S. Environmental Protection Agency (EPA) is granting reconsideration on these two issues as a matter of discretion, voluntarily exercised by the EPA. We intend to issue a *Federal Register* notice initiating public review and comment on these issues. At this time, we are not expressing our views on the appropriateness of reconsidering any of the other issues raised in your petition, which we are continuing to review.

Separate from the two issues identified above for which the EPA is granting reconsideration, the EPA is also taking the opportunity in this letter to provide clarification regarding when owners and operators must conduct performance testing with respect to NHV sampling and storage vessels to demonstrate compliance with the applicable NSPS Subpart OOOOb emission standard. Under NSPS Subpart OOOOb, NHV sampling is considered a monitoring requirement (either continuously or via the 14-day sampling demonstration). The EPA is aware of a large number of storage vessels that have triggered applicability prior to the effective date of the rule that will have to complete initial performance testing requirements.

Per 40 CFR 60.8(a) (the General Provisions for NSPS), a source generally has 180 calendar days after startup to conduct performance (i.e., compliance) testing. As applied to this rule, affected sources that were new, modified, or reconstructed after the supplemental proposal for this rule (December 6, 2022), but before the final rule's effective date of May 7, 2024, have 180 calendar days after the effective date of the rule to conduct performance (i.e., compliance) testing. For NSPS subpart OOOOb sources that are new, modified or reconstructed after the final rule's effective date of May 7, 2024, the applicable monitoring requirements (including the 14-day NHV sampling demonstration) must be completed within 180 calendar days after initial startup of the source. Per 40 CFR 60.8(a), the same 180 calendar day performance (i.e., compliance) demonstration timeframe also applies to any storage vessel.

With respect to the issue of closed vent systems (CVS), we acknowledge API and AXPC's position regarding the "no identifiable emission" standard, and the EPA looks forward to continuing discussions with you on this topic.

If you have any questions regarding this letter, please contact Penny Lassiter at (919) 541-5396 or by email at lassiter.penny@epa.gov. We thank you for your continuing interest in this rule, and we look forward to hearing from you during the rulemaking process for those aspects of the rule that we are reconsidering.

Sincerely,

Tomás Carbonell

Tomás E. Carbonell
Deputy Assistant Administrator for Stationary Sources

cc: Stephanie Hogan, EPA Office of General Counsel, ARLO
Peter Tsirigotis, EPA Office of Air and Radiation, OAQPS

From: Eric Delzer
To: Reiten, John R.; Haase, Reice; Helms, Lynn D.; Axt, Philip J.
Subject: Fw: EPA Grants Reconsideration
Date: Wednesday, May 8, 2024 2:38:46 PM
Attachments: Outlook-zw2c0etc.png
Outlook-q5t0x42l.png
letter-to-api-and-apx.-5.6.24-signed_1.pdf

FYI

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Eric Delzer <edelzer@ndoil.org>
Sent: Wednesday, May 8, 2024 2:34 PM
To: Eric Delzer <edelzer@ndoil.org>
Cc: Ron Ness <ronness@ndoil.org>; Brady Pelton <bpelton@ndoil.org>
Subject: EPA Grants Reconsideration

Good afternoon,

I would like to pass along some good news today.

The EPA has granted the industry's petition for reconsideration of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (89 FR 16820, March 8, 2024) that was submitted on April 5, 2024. I have attached the letter that they sent to API and AXPC granting discretionary reconsideration on:

(1) vent gas net heating value (NHV) monitoring and alternate sampling demonstration requirements for flares and enclosed combustion devices, and

(2) temporary flaring provisions for associated gas in certain situations.

"Without making a determination as to whether these two issues meet the mandatory requirements for reconsideration under CAA section 307(d)(7)(B), the U.S. Environmental Protection Agency (EPA) is granting reconsideration on these two issues as a matter of discretion, voluntarily exercised by the EPA. We intend to issue a Federal Register notice initiating public review and comment on these issues. At this time, we are not expressing our views on the appropriateness of reconsidering any of the other issues raised in your petition, which we are continuing to review."

The EPA also provided clarification and guidance on performance testing NHV storage vessels under OOOOb.

Have a great day!

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Brady Pelton
To: Reiten, John R.
Cc: Eric Delzer
Subject: March 18 Meeting Remote Participation
Date: Wednesday, March 13, 2024 2:28:44 PM
Attachments: image001.png
image002.png

John,
When convenient, please send a Teams link/meeting invitation for the March 18 meeting with Gov's office, AG's office, DMR, DEQ, and industry. I'll share that with our participants who won't be joining us in person.
Thanks,
Brady

Brady Pelton
Vice President & General Counsel

North Dakota Petroleum Council
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

701.223.6380 – Main
701.557.7743 – Direct
701.260.2479 – Cell
bpelton@ndoil.org

www.NDOil.org | www.NDOilFoundation.org

From: Eric Delzer
To: Reiten, John R.; Ron Ness; Brady Pelton
Subject: Re: MHA Oil Production Spreadsheet
Date: Tuesday, March 5, 2024 11:34:16 AM
Attachments: Outlook-s1wngz22.png

Thanks for sharing John. We would be happy to discuss this further when time allows.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Tuesday, March 5, 2024 8:24 AM
To: Ron Ness <ronness@ndoil.org>; Brady Pelton <bpelton@ndoil.org>
Cc: Eric Delzer <edelzer@ndoil.org>
Subject: MHA Oil Production Spreadsheet

Make sure you zoom out so you can see the graphics I created on the right-hand side. In the top chart- orange line is production and blue line is monthly revenue

Please call if you have any questions. I would like to talk more in depth at some point about this issue.

All this information is publicly available.

John

From: Eric Delzer
To: Reiten, John R.
Cc: Norrell, Ryan; Beehler, Jace
Subject: Re: Natural Asset Companies- Governor Burgum Comments
Date: Friday, January 26, 2024 11:00:18 AM
Attachments: Outlook-1e1wf3js.png

Thanks for sharing John. I'm glad you still submitted them for the record.

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Friday, January 26, 2024 10:42 AM
Cc: Norrell, Ryan <ryan.norrell@nd.gov>; Beehler, Jace <jabeehler@nd.gov>
Subject: Natural Asset Companies- Governor Burgum Comments

Good morning and happy Friday,

I have attached two documents to this email detailing our significant concerns regarding the proposed Natural Asset Companies rule. Fortunately, the rule was withdrawn as the comment deadline closed on January 17th; however, we still submitted these comments for inclusion in the public and administrative records.

The first document is our North Dakota special and unique concerns regarding the rule, and the second document is a coalition letter Governor Burgum signed with 6 other Governors.

Feel free to contact us if you have any questions.

Thank you,

John Reiten

From: Eric Delzer
To: Reiten, John R.; Will Houser; Brady Pelton
Subject: RE: NAC Rule withdrawn FYSA
Date: Wednesday, January 17, 2024 3:09:36 PM
Attachments: image001.png

Thanks for sharing John. That's great news!

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Wednesday, January 17, 2024 3:06 PM
To: Will Houser <Will.Houser@clr.com>; Eric Delzer <edelzer@ndoil.org>; Brady Pelton <bpelton@ndoil.org>
Subject: NAC Rule withdrawn FYSA

Please see attached.

John

From: Eric Delzer
To: Reiten, John R.
Cc: Beehler, Jace; Norrell, Ryan
Subject: Re: North Dakota Congressional Support on DAPL
Date: Thursday, February 1, 2024 3:35:47 PM
Attachments: image001.png
Outlook-xp3ptvdm.png

Sounds good John. Maybe in a couple of weeks we can touch base when we both have a little bit better handle on it. Let me know if you need anything from the industry.

Take care,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Thursday, February 1, 2024 1:27 PM
To: Eric Delzer <edelzer@ndoil.org>
Cc: Beehler, Jace <jabeehler@nd.gov>; Norrell, Ryan <ryan.norrell@nd.gov>
Subject: RE: North Dakota Congressional Support on DAPL

All signs point to us commenting. We are working through our internal process right now. We are aware the deadline is speeding toward us…

Thanks!

John

From: Eric Delzer <edelzer@ndoil.org>
Sent: Thursday, February 1, 2024 11:38 AM
To: Reiten, John R. <jreiten@nd.gov>

Cc: Beehler, Jace <jabeehler@nd.gov>; Norrell, Ryan <ryan.norrell@nd.gov>
Subject: Re: North Dakota Congressional Support on DAPL

Awesome to see. Thans for sharing John. I'll make sure our membership gets the message!

Is the state providing comments on the waste emissions charge proposed rule that is due next month? Our members met this morning and decided to submit comments through NDPC. Also, there is a virtual public hearing being held on the rule on February 12th.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Thursday, February 1, 2024 11:32 AM
Cc: Beehler, Jace <jabeehler@nd.gov>; Norrell, Ryan <ryan.norrell@nd.gov>
Subject: North Dakota Congressional Support on DAPL

Good morning

If you come across our CODEL or their team, kindly convey appreciation for the letter!

This was in response to 30 members of Congress urging the USACE to cease operations at DAPL.

North Dakota Delegation Calls for Uninterrupted Operation of the Dakota Access Pipeline (senate.gov)

From earlier:
30-some members of Congress sent to the US Army Corps today expressing concern with a draft

environmental impact statement and climate analysis the agency has prepared for the Dakota Access Pipeline and its Lake Oahe crossing.

https://www.merkley.senate.gov/merkley-grijalva-colleagues-call-to-center-environmental-justice-and-climate-impacts-of-the-dakota-access-pipeline-increase-transparency-and-tribal-consultation-in-final-environmental-impact-statem/

John Reiten

NAME	ORGANIZATION	TICKETS	
NDPC Board			NDPC Hosted:
Kent Kirkhammer	NewKota Services and Rentals	1	
Jason Homiston	ND Energy	1	
Nate Fisher	Enerplus	1	
Todd Slawson	Slawson Exploration	1	
Kevin Gant	XTO Energy	1	
Josh and Katie Blackaby	SandPro	2	
Kate and Wyatt Black	Inland Oil & Gas	2	
Lucas Gjovig	GO Wireline	1	
William Westler	Devon Energy	1	
Lawrence Bender	Fredrikson & Byron P.A.	1	
Todd Shields	ONEOK	1	
Danita and Gordon Bye	Triple T	2	
Michael Kukuk	Chord Energy	1	
Duane Fadness and Ava Widicker	Liberty Resources	2	
Kathy Neset	NESET	1	
Kyle Gardner	Cobra Oil & Gas	1	
Preston Page	Dakota Energy	1	
Craig Smith	Crowley Fleck	1	
Bruce Larson	Kraken Resources	1	
Ryan and Nicole Leininger	New Wave Energy Services	2	
Shane Bryans	Ham's Well Service	1	
Brent and Kolene Lohnes	Hess	2	
Ryan Kopseng	Missouri River Royalty	1	
Kate Klossner	Marathon Petroleum	1	
Kevin Black	Creedence Energy	1	
Tracy Opp	EOG Resources	1	
Bob Mau	Eagle Operating	1	
Josh Ruffo	Enerplus	1	
Eric Sundberg	Slawson Exploration	1	
Whitney Stephenson	Grayson Mill Energy	1	
Jarod Siefert	NewKota	1	
Anna and Eric Nelson	Creedence	2	
Bill Griffin	NESET	1	
Pat Finken	NDPC	1	
Burl and Theresa Evans	Triple T	2	
Darrin Henke	Chord Energy	1	
Kevin Kelly	Chord Energy	1	
Justin Mckie	Cobra Oil & Gas	1	
Seth Hately	Cobra Oil & Gas	1	
Mark Fleming	Spectrum Royalty (Cobra guest)	1	
Brent Sanford	Sanford Consulting	1	
Loren Kopseng	United Energy	1	
Danette Welsh	ONEOK	1	
Zac Weis	Marathon Oil	1	

Ron Rauschenberger	Rauschenberger Consulting	1	
Brad Aman	Continental Resources	2	
Tom Brusegaard		1	
Jessica Bell		1	
Mike Fedorchak		1	
Charlie Gorecki	EERC	1	
John Harju	EERC	1	
John Hamling	EERC	1	
Darren Schmidt	EERC	1	
Tyler Hamman	EERC	1	
Beth Kurz	EERC	1	
Tami Votava	EERC	1	
Jim Sorenson	EERC	1	
Matthew Belobraydic	EERC	1	

NAME	ORGANIZATION	ATTENDING	TOUR
Kent Kirkhammer	NewKota Services and Rentals	Yes	EERC
Mark Anderson	WBI	Yes	No
Jason Homiston	ND Energy	Yes	No
Nate Fisher	Enerplus	Yes	EERC
Todd Slawson	Slawson Exploration	Yes	EERC
Kevin Gant	XTO Energy	Yes	CEM
Josh Blackaby	SandPro	Yes	EERC
Kate Black	Inland Oil & Gas	Yes	EERC
Lucas Gjovig	GO Wireline	Yes	EERC
Josh DeMorrett	ConocoPhillips	Yes	EERC
William Westler	Devon Energy	Yes	EERC
Lawrence Bender	Fredrikson & Byron P.A.	Yes	No
Todd Shields	ONEOK	Yes	EERC
Danita Bye	Triple T	Yes	EERC
Michael Kukuk	Chord Energy	Yes	EERC
Duane Fadness	Liberty	Yes	EERC
Preston Page	Dakota Energy	Yes	EERC
Craig Smith	Crowley Fleck	Yes	EERC
Kathy Neset	NESET	Yes	CEM
Duane Klabunde	Enbridge	No	No
Kyle Gardner	Cobra Oil & Gas	Yes	
Bruce Larson	Kraken Resources	Yes	EERC
Ryan Leininger	New Wave Energy Services	Yes	EERC
Shane Bryans	Ham's Well Service	Yes	EERC
Brent Lohnes	Hess	Yes	CEM
Ryan Kopseng	Missouri River Royalty	Yes	EERC
Kate Klossner	Marathon Petroleum	Yes	No
Kevin Black	Creedence Energy	Yes	EERC
Tracy Opp	EOG Resources	Yes	EERC
Bob Mau	Eagle Operating Inc.	Yes	EERC
Ron Ness	NDPC	Yes	EERC
Brady Pelton	NDPC	Yes	CEM
Micaela Rud	NDPC	Yes	No
Tessa Sandstrom	NDPC	Yes	No
Reva Kautz	NDPC	Yes	EERC
Eric Delzer	NDPC	Yes	EERC
Josh Ruffo	Enerplus	Yes	EERC
Eric Sundberg	Slawson Exploration	Yes	EERC
Wyatt Black	Inland Oil & Gas	Yes	EERC
Whitney Stephenson	Grayson Mill	Yes	EERC
Jarod Seifert	NewKota	Yes	EERC
Pat Finken	NDPC	Yes	No
Gordon Bye	Triple T	Yes	EERC
Burl Evans	Triple T	Yes	EERC
Theresa Evans	Triple T	Yes	EERC

Darrin Henke	Chord Energy	Yes	EERC
Kevin Kelly	Chord Energy	Yes	EERC
Bill Griffin	NESET	Yes	CEM
Justin Mckie	Cobra Oil & Gas	Yes	
Seth Hately	Cobra Oil & Gas	Yes	
Mark Fleming	Cobra Oil & Gas	Yes	
Ron Rauschenberger	Rauschenberger Consulting	Yes	
Brent Sanford	Sanford Consulting	Yes	CEM
Loren Kopseng	Missouri River Royalty	Yes	EERC
Eric Nelson	Creedence	Yes	EERC
Anna Nelson	Creedence	Yes	EERC
Danette Welsh	ONEOK	Yes	No
Will Houser	Continental Resouces	Yes	No
Brad Aman	Continental Resouces	Yes	EERC
John Argo	Continental Resouces	Yes	EERC
Robin Turner	UND Alumni Foundation	Yes	CEM
Peter Johnson	UND Alumni Foundation	Yes	CEM
Brian Tande	UND	Yes	CEM
Brent Bogar	AE2S	Yes	EERC
Mike Dunn	Construction Engineers	Yes	EERC
Zac Ista	State Representative	Yes	No
John Reiten	Policy Advisor	Yes	CEM
Jeff Barta	State Senator	Yes	EERC
Dale Patten	State Senator	Yes	EERC
Mark Sanford	State Representative	Yes	CEM
Scott Meyer	State Senator	Yes	EERC
Mike Beltz	State Representative	Yes	CEM
Doug Goehring	Ag Commissioner	Yes	CEM
Tammy Miller	Lt. Governor	Yes	CEM
Brandon Bochenski	GF Mayor	Yes	No
Don Vigesaa	State Representative	Yes	EERC
Jon Sickler	State Senator	Yes	CEM
Mike Nathe	State Representative	Yes	EERC
David Hogue	State Senator	Yes	EERC
Alisa Mitskog	State Representative	Yes	EERC
Claire Cory	State Representative	Yes	CEM
Brad Bekkedahl	State Senator	Yes	EERC
Scott Snyder	VP Research & Economic Development	Yes	EERC
Greg Stemen	State Representative	Yes	EERC
Randy Richards	Office of Kevin Cramer	Yes	EERC
Craig Headland	State Representative	Yes	EERC
Kristin Roers	State Senator	Yes	EERC
Andrea Travnicek	ND Dir. Of Water Resources	Yes	EERC
Scott Shofield	State Representative	No	EERC
Roz Leighton	Kelly Armstrong Office	Yes	No
Kjersti Armstrong	Kelly Armstrong Office	Yes	No
Julie Fedorchak	ND PSC	Yes	No

John Hoeven	US Senator	Yes	No
Jessica Lee	Hoeven's office	Yes	No
Tom Brusegaard	Hoeven's office	Yes	No
Invited			
Jared Hagert	State Representative		
Randy Lemm	State Senator		
Doug Burgum	Governor		
Drew Wrigley	Attorney General		
Steve Vitter	State Representative		
Ron Sorvaag	State Senator		
Todd Porter	State Representative		
Emily O'Brien	State Representative		
Eric Murphy	State Representative		
Mike Lefore	State Representative		
Curt Kreun	State Senator		
Corey Mock	State Representative		

From: Brady Pelton
To: Reiten, John R.
Cc: Ron Ness
Subject: NDPC Board Event Attendee Lists
Date: Tuesday, February 27, 2024 4:39:27 PM
Attachments: image001.png
image002.png
EERC Luncheon and Tour RSVP List - 03.01.2024.xlsx
2024 BoD Hockey Tickets and Suites.xlsx

John,

Attached are the RSVP lists we've compiled for the EERC luncheon and EERC/College of Engineering and Mines tours as well as the UND hockey game, both taking place Friday, March 1.

Note the two tabs on the hockey game RSVP list. The UND Alumni Association (Suite 225) is where we have Governor Burgum, Lt. Governor Miller, Jace Beehler, and yourself. That suite list is located at the bottom of the first tab. The second tab includes members of our Board, event sponsors, and other guests.

BRADY PELTON
Vice President & General Counsel

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From: Eric Delzer
To: Axt, Philip J.
Cc: Reiten, John R.; Brady Pelton
Subject: Oil and Gas Leasing Rule Challenge
Date: Tuesday, May 7, 2024 4:03:36 PM
Attachments: Outlook-12pjw3x3.png

Good afternoon Phil,

I tried calling but couldn't make a connection. I just wanted to let you know that Western Energy Alliance will be filing a challenge to the BLM leasing rule next week, mainly on the grounds of the prohibitive bonding rates. NDPC will likely be joining them as a co-plaintiff. It is my understanding that this suit will be filed in Wyoming, but WEA may file on the conservation and landscape health rule up here in the 8th Circuit.

Let me know if you have any questions.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

September 22, 2023

Via Regulations.gov

Tracy Stone-Manning, Director (630)
U.S. Department of the Interior
Bureau of Land Management
1849 C St. NW, Room 5646
Washington, DC 20240

Re: Oil and Natural Gas Associations' Comments on BLM's Proposed Rule, Fluid Mineral Leases and Leasing Process, 88 Fed. Reg. 47,562 (July 24, 2023), RIN 1004-AE80, Docket ID: BLM-2023-0005-0003 ("Proposed Rule")

Dear Ms. Stone-Manning:

The American Petroleum Institute ("API"), Alaska Oil and Gas Association ("AOGA"), American Exploration and Production Council ("AXPC"), Colorado Oil & Gas Association ("COGA"), West Slope Colorado Oil and Gas Association ("WSCOGA"), Independent Petroleum Association of America ("IPAA"), Montana Petroleum Association ("MPA"), New

Mexico Oil and Gas Association ("NMOGA"), North Dakota Petroleum Council ("NDPC"), Petroleum Alliance of Oklahoma, Permian Basin Petroleum Association ("PBPA"), Utah Petroleum Association ("UPA"), Western States Petroleum Alliance ("WSPA"), and Petroleum Alliance of Wyoming ("PAW") (collectively "the Associations") appreciate the opportunity to submit comments on the above-referenced Bureau of Land Management ("BLM") Proposed Rule.

The Associations support BLM's goal of ensuring fair returns for the American public from activities on federal lands, but we are concerned that BLM's approach with this rule overreaches its statutory authority and could have a damaging impact on U.S. energy security and the economy. First, these changes disregard Congress' and multiple courts' rejection of the Administration's recent attempts to dramatically curtail federal oil and natural gas leases.[1] Second, these changes reject existing robust planning and environmental review processes. Instead, they enhance BLM discretion to constrain onshore access—both procedurally and on a case-by-case basis. Third, these changes may compromise the Administration's environmental goals by creating greater dependence on foreign sources for American energy needs. While the demand for oil and natural gas persists—which the Administration has repeatedly acknowledged will be true for the foreseeable future—it is often preferable to have that production occurring domestically and on federally-managed lands rather than from other locations or energy sources that have a more significant environmental footprint. Therefore, BLM should abandon several aspects of this Proposed Rule, or at a minimum, substantially revise and re-propose them to reflect functional and effective regulations prior to issuing any final rule.

THE ASSOCIATIONS' INTERESTS

API is the only national trade association representing all facets of the oil and natural gas industry, which supports more than 10 million U.S. jobs and nearly 8 percent of the U.S. economy. API's nearly 600 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of Americans. Many API members have a keen interest in the Proposed Rule because they currently hold interests in or operate federal onshore oil and gas leases throughout the United States.

AOGA is a non-profit trade association located in Anchorage, Alaska. AOGA's member companies account for the majority of oil and gas exploration, development, production, transportation, refining, and marketing activities in Alaska. AOGA and its members are longstanding supporters of federal lands use, conservation, management, and research in the Arctic.

AXPC is a national trade association representing 34 leading independent oil and natural gas exploration and production companies in the United States. AXPC companies support millions of Americans in high-paying jobs and invest a wealth of resources in our communities.

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[1] *See, e.g.*, Inflation Reduction Act of 2022, Pub. Law No. 117-169; *State of North Dakota v. U.S. Dep't of Interior, et al.*, No, 21-148, ECF No. 98 (D.N.D. Mar. 27, 2023) (slip. op.); *Louisiana v. Biden*, 622 F. Supp. 3d 267 (W.D. La. 2022).

Dedicated to safety, stewardship, and technological advancement, AXPC's members strive to deliver affordable, reliable energy to consumers while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand and promote the importance of advancing positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. AXPC's members are committed to being good stewards of federal and Indian resources and operating in compliance with all federal requirements. AXPC member companies produce more than half of U.S. onshore production each year.

COGA is a non-profit trade organization that represents over 200 companies throughout the state of Colorado. For nearly 40 years, COGA has sought to create a thriving, innovative and respected oil and natural gas industry in Colorado that embodies the values of our communities, prioritizes the protection of our environment, and provides the natural resources that advance our society. COGA provides a positive, unified, and proactive voice for the oil and natural gas industry in Colorado.

As a membership association representing oil and gas exploration, production, and midstream companies, **WSCOGA** members will be directly impacted by the results of this rulemaking and has a significant interest in ensuring clarity, consistency, and fairness in the further development of oil and gas regulations. WSCOGA provides a unified political and regulatory voice for the oil and natural gas industry in the Piceance Basin and the rest of Western Colorado. WSCOGA's represents over 90 member companies and its mission is to produce natural gas products for the benefit of society.

IPAA is a national upstream trade association representing thousands of independent oil and natural gas producers and service companies across the United States. Independent producers develop 91 percent of the nation's oil and natural gas wells. These companies account for 83 percent of America's oil production, 90 percent of its natural gas and natural gas liquids (NGL) production, and support over 4.5 million American jobs.

MPA is a Montana-based trade association representing over 150 member-companies involved in all aspects of the oil and natural gas industry. MPA's members include producers, refiners, suppliers, pipeline operators, transporters, and mineral owners as well as service and supply companies that support all segments of the industry and employ a substantial number of hard-working Montanans.

NMOGA is a coalition of oil and natural gas companies, individuals, and stakeholders dedicated to promoting the safe and environmentally responsible development of oil and natural gas resources in New Mexico. Representing over 1,000 members, NMOGA works with elected officials, community leaders, industry experts, and the general public, to advocate for responsible oil and natural gas policies and increase public understanding of industry operations and contributions to the state. New Mexico's oil and natural gas activity is concentrated in two areas: the Permian Basin in the southeast and the San Juan Basin in the northwest. New Mexico is one of the United States' leading producers, ranking 2nd in annual oil production and 9th in annual natural gas production. New Mexico is attracting interest and attention from around the globe, as the Permian Basin undergoes a resurgence of production and investment activity.

Established in 1952, **NDPC** is the trade association and primary voice for the oil and gas industry in North Dakota. NDPC represents more than 550 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline development and operation, transportation, mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky Mountain Region. The mission of NDPC is to promote opportunities for open discussion, lawful interchange of information, and education concerning the petroleum industry; to monitor and influence legislative and regulatory activities on the state and national level; and to accumulate and disseminate information concerning the petroleum industry to foster the best interests of the public and industry.

The **Petroleum Alliance of Oklahoma** represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. Its members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas.

PBPA is the largest regional oil and gas association in the United States. We represent the men and women who work in the oil and gas industry in the Permian Basin of West Texas and southeastern New Mexico. The Permian Basin is the largest inland oil and gas reservoir and the largest oil and gas producing region in the world. PBPA consists of the largest producers as well as the smallest operators in the Permian Basin. Part of PBPA's mission is to promote environmentally conscious operations and sustainable economic profitability among all our members, large and small.

UPA is a statewide oil and gas trade association established in 1958 representing companies involved in all aspects of Utah's oil and gas industry. UPA members range from independent producers to midstream and service providers, to major oil and natural gas companies widely recognized as industry leaders responsible for driving technology advancement resulting in environmental and efficiency gains. UPA members operate extensively on federal lands and have a long history of stewardship and conservation.

WSPA is a non-profit trade association that represents companies that account for the bulk of petroleum exploration, production, refining, transportation and marketing in the five western states of Arizona, California, Nevada, Oregon, and Washington. WSPA members operate in upstream, midstream, and downstream segments of the oil and natural gas industry.

PAW represents companies involved in all aspects of responsible oil and natural gas development in Wyoming, including upstream production, oilfield services, midstream processing, pipeline transportation and essential work such as legal services, accounting, consulting and more. PAW advocates for oil and gas development that supports sustainable production of Wyoming's abundant resources; fosters mutually beneficial relationships with Wyoming's landowners, businesses, and communities; and upholds the values of science-based, environmental stewardship. Eighty-five percent of the oil and gas companies operating in Wyoming are classified as small businesses.

GENERAL COMMENTS

The Associations generally support BLM's effort to update and clarify the federal onshore oil and natural gas leasing and lease management regulations. The Associations support the proposed changes that implement the Inflation Reduction Act ("IRA") as well as those that reduce and streamline filing and recordkeeping requirements. However, the Associations have multiple concerns with the rule. Among other shortcomings, it contravenes BLM's statutory authority and does not reflect the foundational concepts of the Federal Land Policy and Management Act ("FLPMA") and BLM's mission. The Associations' comments and concerns about the Proposed Rule reflect certain foundational concepts that should shape any BLM regulation:

1. Onshore federal fluid minerals should remain a viable and attractive investment option with a balanced, predictable, and equitable leasing and lease management process.

2. The Associations disagree that the existing regulations governing BLM's discretionary functions are inadequate to protect the fiscal interests of the American public, which include not only direct proceeds from leasing, but also affordable, abundant, domestic energy that lowers prices at the pump and broadens foreign policy options.

3. The Associations disagree that the existing regulations fail to promote leasing practices that are consistent with diligent development requirements and multiple-use and sustained-yield principles. BLM should not limit areas available for leasing by directing leasing to what BLM subjectively considers "appropriate" locations, either under its informal expression of interest ("EOI") process or its proposed formal nomination process. Regional planning, National Environmental Policy Act ("NEPA") reviews, and other processes already conduct the requisite balancing in identifying suitable areas for leasing.

4. BLM cannot adopt new leasing procedures that sidestep or dilute its statutory obligation to conduct quarterly lease sales in each state.

5. BLM cannot adopt regulatory changes that unduly constrain opportunities for development and operations on already-issued leases or that breach or otherwise unduly impair rights conferred under those leases.

6. BLM cannot confer undue authority on other Department of the Interior ("DOI") bureaus, and other surface managing agencies, to constrain leasing and development of oil and natural gas leases on federally-managed lands.

7. BLM should not impose undue bonding and additional financial burdens on the oil and natural gas industry beyond new statutory requirements under the IRA.

8. BLM should not "streamline" disqualification of entities from existing or new leases, akin to suspension and debarment but without corresponding due process.

The likely impacts of this Proposed Rule appear to exacerbate challenges created by other recent proposals and efforts by BLM and other federal agencies, thereby decreasing domestic energy supplies and undermining energy security. The Associations refer BLM to, and incorporate by reference, their submitted comments on those regulatory proposals.[2]

A. Federal Onshore Oil and Natural Gas Leasing Is Critical to the United States' Global Leadership in Energy Production.

The U.S. is a global leader in both emissions reductions[3] and energy production.[4] Oil and natural gas exploration and development on federal lands and waters provide enormous benefits to our nation and its citizens—for our economy, our environment, and our national security. Because of the vital importance of energy production on public lands, overreaching land management regulations place our domestic energy supply at risk. Reduced production on federal lands also harms local communities that depend upon the jobs and revenues generated by lawful energy development. To the extent BLM's Proposed Rule reduces opportunities for oil and gas development on public lands, the U.S. and its allies will likely import more oil and natural gas from countries that may have lower environmental standards and could revert to coal for power generation, resulting in higher emissions domestically and internationally—precisely the opposite of the Administration's overriding policy objectives.[5]

The U.S. oil and natural gas industry produces and delivers nearly 70% of the energy our country uses. Our nation and the world will continue to need reliable, affordable oil and natural gas - energy that will serve as the foundation for broader opportunities for decades to come. Oil and natural gas production on public lands is a crucial part of the nation's program for energy security and economic strength. Likewise, the oil and natural gas industry is essential to supporting a modern standard of living by providing communities with access to affordable, reliable, and cleaner energy. The industry's top priority remains public health and safety, and our member companies have well-established policies in place for proactive community engagement and feedback aimed at fostering a culture of trust, inclusivity, and transparency.

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[2] *See, e.g.*, BLM, Waste Prevention, Production Subject to Royalties, and Resource Conservation, 87 Fed. Reg. 73,588 (Nov. 30, 2022); BLM, Conservation and Landscape Health Proposed Rule, 88 Fed. Reg. 19,583 (April 3, 2023); Council on Environmental Quality ("CEQ"), National Environmental Policy Act Implementing Regulations Revisions Phase 2, 88 Fed. Reg. 49,924 (July 31, 2023).

[3] According to EPA, "Between 1970 and 2020, the combined emissions of the six common pollutants (PM2.5 and PM10, SO2, NOx, VOCs, CO and Pb) dropped by 78 percent. This progress occurred while U.S. economic indicators remain strong." EPA, *Progress Cleaning the Air and Improving People's Health* (May 1, 2023), https://www.epa.gov/clean-air-act-overview/progress-cleaning-air-and-improving-peoples-health#pollution.

[4] According to the Energy Information Administration, the United States is ranked first globally in total energy production from both natural gas and from petroleum and other liquids. U.S. Energy Info. Admin., *Total Energy Production from Natural Gas*, https://www.eia.gov/international/rankings/world?.pa=287&u=2&f=A&v=none&y=01%2F01%2F2021.

[5] The International Energy Agency reports that coal consumption rose 3.3% in 2022. https://www.iea.org/news/global-coal-demand-set-to-remain-at-record-levels-in-2023.

The Associations and their members believe that all people should be treated fairly, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. In this regard, it is crucial to bear in mind that oil and natural gas development on federal lands promotes investment in rural areas where state and local economies depend on the industry for jobs, continued economic prosperity, and revenue generated from state severance taxes and local taxes generated from these projects.

Just as importantly, the Associations' members support the health and sustainability of public lands and resources. The oil and natural gas industry employs technology and strategies as part of its support for environmental stewardship—taking measures to prioritize protecting public health and the environment, while working to deliver plentiful energy. Measures for the protection of species, habitats, and groundwater are all part of the Associations' members' approach to oil and natural gas development, and projects are designed, managed, and operated to identify and address potential environmental impacts associated with activities ranging from initial exploration to eventual closure. The Associations' members make unparalleled efforts to improve the compatibility of their operations with the environment while responsibly and economically developing energy resources and supplying high quality products and services to consumers. Indeed, across these varied operations, the Associations' members are working continually to minimize and reduce impacts to air, water, and land resources, including to protected species and habitats. At the same time, the Associations' members implement and improve innovative practices and technology while continuing to bolster research that looks for new ways to further enhance environmental performance.

In addition, the Associations and their members monitor, compile and report emissions data per government regulations and on a voluntary basis as appropriate, conduct studies with academic institutions, and work closely with state and federal regulators. This type of collaboration has resulted in improved habitat and species health. For example, modern energy production methods and technologies have resulted in a 70% reduction in surface disturbance when compared to historical practices.[6] The industry also works with many stakeholder groups to understand wildlife migration patterns and routes in areas where operations occur. In particular, oil and natural gas production on BLM lands provides immense value for the nation. BLM manages approximately 245 million acres of surface estate on public lands in the United States (more than any other federal agency).[7] BLM also manages the federal government's onshore subsurface mineral estate (approximately 700 million acres).[8]

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[6] *See* David H. Applegate & Nicholas Owens, *Oil and Gas Impacts on Wyoming's Sagegrouse: Summarizing the Past and Predicting the Foreseeable Future*, 8 HUMAN–WILDLIFE INTERACTIONS 284, 289–90 (2014), https://www.researchgate.net/publication/267765279_Oil_and_Gas_Impacts_on_Wyoming%27s_Sagegrouse_Summarizing_the_Past_and_Predicting_the_Foreseeable_Future.

[7] The White House, *Department of the Interior, in* THE BUDGET FOR FISCAL YEAR 2024 (2023), https://www.whitehouse.gov/wp-content/uploads/2023/03/int_fy2024.pdf.

[8] BLM, *About the BLM Oil and Gas Program*, https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/about#:~:text=The%20BLM%20manages%20the%20Federal,benefit%20of%20the%20American%20public.

The Congressional Research Service ("CRS") recently explained the enormous importance of oil and natural production on federal lands to the federal government, the states, local communities, and the nation as a whole.[9] Production of oil and natural gas from onshore federal lands represents almost 10% of total domestic production of crude oil and natural gas. CRS found that total revenues from oil and natural gas leases on onshore federal lands exceeded $4.2 billion in fiscal year 2019. This substantial return for the taxpayer is comprised of royalty and interest payments, bonuses, rentals, and other sources. In turn, these funds were disbursed to states (more than $2 billion), the Reclamation Fund (more than $1.5 billion), and the U.S. Treasury ($444 million), among other recipients.[10]

More recent data published by DOI's Office of Natural Resources Revenue ("ONRR") shows that, for fiscal year 2022, federal leases generated more than $7.6 billion in revenues (from bonus bids, royalties, rents, and other sources).[11] For fiscal year 2022, ONRR disbursed over $4.3 billion in funds collected from leasing activities on federal lands and waters to 33 states.[12] As stated by CRS, "[f]ederal revenues from oil and natural gas leases provide income streams that support a range of federal and state policies and programs."

Relevant benefits also extend beyond direct proceeds from BLM onshore oil and gas leases. The Associations refer BLM to and incorporate by reference the attached analysis of "Economic Benefits of Onshore Federal Oil and Natural Gas Leasing." Based on reliable modeling, in fiscal year 2022, onshore federal oil and natural gas development supported nearly 250,000 jobs, generated $19.4 billion in labor income, and contributed $36.7 billion to U.S. Gross Domestic Product ("GDP"). More broadly, between fiscal year 2013 and fiscal year 2022, onshore federal oil and natural gas leasing supported an average of 190,000 jobs, generated $13.4 billion in labor income, and contributed $24.2 billion to GDP each year.

The many added costs and burdens in the Proposed Rule needlessly place these substantial economic returns at risk. This concern is heightened for marginal properties for which the Proposed Rule's new bonding and other burdens could accelerate termination and thereby result in waste of federal oil and natural gas. Moreover, the Proposed Rule could undercut its stated environmental justice aims by reducing good jobs and economic benefits for otherwise disadvantaged communities that stem from onshore federal oil and gas activities.

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[9] BRANDON S. TRACY, CONG. RES. SERV., R46537, REVENUES AND DISBURSEMENTS FROM OIL AND NATURAL GAS PRODUCTION ON FEDERAL LANDS (2020), https://crsreports.congress.gov/product/pdf/R/R46537.

[10] *Id.*

[11] DOI, *Interior Department Announces $21.53 Billion in Fiscal Year 2022 Energy Revenue, Highest-Ever Disbursements from Clean Energy from Federal Lands and Waters* (Nov. 4, 2022) [*hereinafter FY 2022 Announcement*], https://www.onrr.gov/press-releases/FY2022.Disbursements.Press.Release.pdf.

[12] *Id.*

B. The Proposed Rule Inappropriately Stifles Critical Domestic Energy.

Though purporting to principally implement statutory changes enacted in the IRA, the Proposed Rule includes other significant changes that could dramatically and inappropriately curtail oil and natural gas leasing and corresponding production. Several proposed provisions introduce new uncertainty into BLM's leasing process. In doing so, contrary to its preamble's assertions, the Proposed Rule contradicts directives to BLM for "improvements in the Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends." 88 Fed. Reg. at 47,608 (citing Executive Order 13563).

Perhaps of greatest concern is the Proposed Rule's creation and implementation of new "preference criteria" that are opaque and subjective. Emblematic of the Proposed Rule's flawed approach is its assertion that "this approach would provide stakeholders with greater certainty, as it would be understood at the outset of the leasing process that the preference criteria would guide the BLM's decision-making." *Id.* at 47,566-67. But the only such added certainty appears to be substantially less oil and natural gas leasing, as BLM's non-"preference" of certain areas would likely amount to their indefinite exclusion from leasing. That is, the Proposed Rule would repeatedly defer the leasing of promising oil and natural gas prospects, instead "directing leasing toward areas that do not have" what BLM perceives to be "any sensitive cultural, wildlife, and recreation resources." *Id.* at 47,566. It is disconcerting that BLM would attempt to shift toward subjective judgments rather than rely on already-existing intensive planning efforts, NEPA reviews, and other environmental safeguards making such onshore areas suitable for oil and natural gas leasing.

If implemented as written, the Proposed Rule could essentially eliminate the opportunity for exploration or the expansion of newly discovered producing areas, constrain future oil and natural gas development to areas where it already exists, and shrink such areas even further, thereby discouraging further innovation, new discoveries, and ultimately domestic production. Even after accepting nominations and holding lease sales, BLM would reserve the ability to impose new conditions and ultimately deny leases. Additionally, despite BLM only nominally offering acreage for leasing or itself nominating tracts in which industry has indicated no interest, BLM could nonetheless unduly count such acreage against its IRA minimums for onshore oil and natural gas leasing to enable BLM to issue rights-of-way for wind and solar energy development on federal lands.

Vague rules and standards create substantial uncertainty, undermine investor confidence, and reduce the value and reliability of partnerships with federal agencies on shared efforts to responsibly operate on and around federal lands and resources. Through statutes like FLPMA, longstanding agency regulations and policies, and judicial decisions, the concepts of "multiple use" and "sustained yield" have become well understood. Yet a variety of provisions in the Proposed Rule, employing many undefined or ill-defined key terms, would create uncertainty about implementation of this existing framework, while also adding a host of other new policies and tools that will further exacerbate that uncertainty. Such problematic provisions include, but are not limited to: (1) novel and undefined "preference criteria"; (2) broad and summary disqualification of persons from bidding on and receiving leases; (3) unnecessarily added steps and opportunities for BLM to further restrict lease terms or otherwise deter leasing during the leasing process; (4) open-ended operational restrictions announced within and even after lease sales; (5) needless tying up of capital via substantially greater bonding requirements; and (6) impermissible creation of veto authority in other agencies that has no statutory foundation.

The results of such uncertainty in the Proposed Rule would be the following: create, (rather than obviate) conflict among key stakeholders and uses; reduce the regulatory certainty that is essential to support investment in economically productive uses; and hinder the ability of BLM to achieve the congressional mandates set forth in FLPMA and the Mineral Leasing Act ("MLA"). Therefore, BLM should revise and re-propose its Proposed Rule to properly manage federal lands for energy production among other statutory purposes and to ensure companies have a clear understanding of what they are bidding on and the lease terms that will govern their property rights. Ultimately, BLM and industry should work in concert to provide responsible and reliable domestic energy leasing and production that benefits the U.S. public.

The Proposed Rule is particularly concerning for the western states, which contain 99% of all lands managed by BLM. The MLA provides that "lease sales shall be held for each State where eligible lands are available at least quarterly and more frequently if the Secretary of the Interior determines such sales are necessary." 30 U.S.C. § 226. The MLA further provides that, as a general matter, 50% of money received from sales, bonuses, royalties, and rentals is distributed to the states where the leased lands are located. As noted above, for fiscal year 2022, federal leases generated over $7.6 billion in revenues (from bonus bids, royalties, rents, etc.). For fiscal year 2022, the ONRR disbursed over $4.3 billion in funds collected from leasing activities on federal lands and waters to 33 states.[13]

According to revenue data published by ONRR,[14] during fiscal year 2022, more than $8.8 billion was distributed to federal and local governments and Native American tribes as a result of federal *onshore* production alone (the majority of which comes from oil and natural gas production on federal lands). During that same period, almost 440 million barrels of oil and almost 3.5 trillion cubic feet of natural gas were produced from federal onshore lands. For New Mexico alone, disbursements from onshore energy production resulted in over $2.7 billion in disbursements to state and local governments in fiscal year 2022. In the same period, Wyoming received over $785 million in disbursements for onshore production. Additional funds are distributed to states via the Reclamation Fund, which supports critical infrastructure in local communities; the Land and Water Conservation Fund, which supports state and local efforts to conserve areas; and the Historic Preservation Fund, which supports efforts to preserve historical and cultural resources through state and local grants.

As previously noted, CRS has explained that "[f]ederal revenues from oil and natural gas leases provide income streams that support a range of federal and state policies and programs."[15] States and local governments use these funds to support a variety of needs,

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[13] DOI, *FY 2022 Announcement*, *supra*.

[14] DOI, *Natural Resources Revenue Data* (May 26, 2023), https://revenuedata.doi.gov/.

[15] TRACY, *supra*. According to the Western Governors Association, "The federal government has codified several historic agreements and programs to compensate western states for reduced revenue associated with the presence of tax-exempt federal lands within their borders. Western Governors call upon the federal government to honor its statutory obligations to share royalty

including funding for schools, social services, and infrastructure. Because of the direct connection between energy leasing and production and state and local revenues, the Proposed Rule risks cuts to these revenues and, hence, direct harm to these states and communities.

Another consideration, not analyzed in the Proposed Rule, is that due to the checkerboard nature of federal tracts in some states, state and private mineral interests adjacent to BLM lands could be adversely impacted by the Proposed Rule. *Cf. Wyoming v. DOI*, 493 F. Supp. 1046, 1083 ("BLM's implementing regulations have historically maintained this distinction between its general regulatory authority over Federal leases and its more limited authority with respect to the private and State leases that may be pooled with Federal interests."). This could result in delays or complete exclusion of such non-federal minerals in addition to the previously-mentioned loss in federal bonuses and royalties. BLM thus should further engage directly with the states where BLM lands are situated to ensure that new BLM policies and rulemakings do not result in unjustified impacts on these areas.

C. The Proposed Rule Imposes Unreasonable New Financial Burdens on Lessees and Operators.

The cumulative effect of the additional costs BLM is proposing to add, coupled with the already increased costs required by the IRA, is to impose potentially stifling financial burdens on federal oil and gas lessees and operators. The consequence will be that many existing lessees and operators may no longer be able to continue operating their federal leases, and the number of potential lessees willing to bid for new federal lease interests in future competitive lease sales may decline as well.

The IRA imposes mandatory increased fees on lessees and operators that BLM is implementing through the Proposed Rule. The minimum royalty rate for new oil and gas leases is increasing from 12 ½ percent to 16 2/3 percent. Royalty rates for reinstated leases also are increasing from 16 2/3 percent to 20 percent. The IRA increases the minimum bid amount from $2 per acre to $20 per acre. Rental rates are increased from $1.50 per acre to $3 per acre the first two years of the lease (100 percent increase), $1.50 per acre to $5 per acre the next three years (233 percent increase), $2 per acre to $5 per acre for years six through eight (150 percent increase), and $2 per acre to $15 per acre the last two lease years (650 percent increase). Rental rates for reinstated leases similarly are increased from $10 per acre to $20 per acre (100 percent increase). The IRA also imposes a new $5 per acre fee (indexed to inflation) for any person that submits an expression of interest in leasing federal lands.

The cumulative impact of these congressionally-mandated increased rates and fees on federal lessees and operators without doubt will be extraordinarily burdensome. Yet BLM is proposing to simultaneously exacerbate those burdens via the Proposed Rule that would impose

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and lease payments with states and counties. States, as recipients of revenues from these programs and agreements, should be provided meaningful and substantial opportunities for consultation in the development of federal policy affecting those revenues." W. Governor's Ass'n, *WGA Policy Resolution 2023-02* (Dec. 7, 2022), https://westgov.org/resolutions/article/wga-policy-resolution-2023-02-states-share-of-royalties-and-leasing-revenues-from-federal-lands-and-minerals.

other substantial cost increases, some that even Congress was unwilling to impose at the same time as the broad increases described above. While Congress declined to do so, BLM is proposing to increase the lease bond that an operator must provide to BLM from $10,000 to $150,000 (1,500 percent increase), and the state-wide bond from $25,000 to $500,000 (2,000 percent increase). BLM also is proposing to eliminate nationwide bonds entirely, depriving lessees and operators of a financial tool currently available to mitigate bonding costs by spreading them over a larger universe of leases. BLM also is proposing to increase a range of processing and filing fees by several hundred percent, including raising the fee for an Application for Permit to Drill to $11,805, a large increase over the current fee.

The detrimental effect of these staggering cumulative rate and fee increases will fall disproportionately on smaller lessees and operators who operate the marginal properties that constitute a substantial percentage of production from federal leases. The negative economic impacts likely will cause some operators to cease operations on these marginal properties, permanently stranding and thereby wasting federal oil and gas resources inconsistent with long-standing statutory federal mineral leasing principles. The increased costs to operate on federal leases also will deter smaller operators from participating in future lease sales, constraining competition and likely causing an overall reduction in future bonus bids.

It is serious error for BLM to assume that oil and natural gas lessees and operators will be able to absorb these cumulative cost increases and continue business as usual on federal lands. Indeed, the Proposed Rule does not meaningfully evaluate its economic effects in the real-world context of contemporaneous IRA-based cost increases. Where BLM does quantify costs of certain proposed provisions codifying the IRA, BLM appears to understate them. For example, based on the last five years of National Fluids Lease Sale System data, annual EOI fees increases appear to be about 145 percent higher (approximately $9.3 million) than BLM estimates (approximately $3.8 million). Nor does the Proposed Rule assess its economic effects aggregated with other BLM and Administration initiatives placing even more costs on federal oil and gas lessees and operators.

To the contrary, the Proposed Rule inappropriately downplays its economic impacts on the regulated community, particularly small businesses. For example, with respect to BLM's proposed new bonding costs, BLM's RFA analysis states that "the annual cost to secure a bond would not be material," suggesting the increased bonding might have some limited impact on small businesses. *Id.* at 47,609. That is because BLM claims that buying a bond is only 1 to 3.5 percent of the bond value on an annual basis. That simplistic metric provides an incomplete picture. For example, even premiums comprising a small percentage of the Proposed Rule's sharply increased bonding requirements may impose a significant burden on the bottom line of a small business, particularly if those premiums must be paid each year of the lease. The Proposed Rule also presumes equal access to bonding. Moreover, certain industry experts anticipate that small companies may need to self-bond the entire amount in some instances. Thus, BLM must adopt a more holistic and pragmatic economic analysis before proceeding to any final rule.

SECTION-BY-SECTION COMMENTS

BLM is proposing changes simultaneously to a large number of existing regulations. For ease of reference, the Associations' comments below follow the same organization of sections as in the Proposed Rule. Many of the modifications to sections in the Proposed Rule include only grammatical or similar minor modifications to reflect an updated style, and do not include any substantive changes to BLM's existing regulations. The Associations are not providing any comment on those sections, and generally support those modifications.

The Associations offer comments on several sections with proposed substantive changes to the Proposed Rule's regulatory text. For clarity, throughout these comments, the Associations provide suggested regulatory text revisions in redline format to facilitate BLM's consideration:

- Recommended language for removal is indicated in ~~strikethrough text~~, except where the Associations recommend deletion of a provision of the Proposed Rule in its entirety.
- Recommended language for addition is indicated in <u>underlined text.</u>

References herein to existing regulatory sections are to title 43 of the Code of Federal Regulations unless specified otherwise.

I. PART 3000

A. § 3000.5 Definitions.

The Associations generally support BLM's efforts to clarify, simplify, and contemporize the definitions section for part 3000. However, BLM should not create a new definition of "person." It instead should use the definition of that term in the Federal Oil and Gas Royalty Management Act, 30 U.S.C. § 1702, that already applies to BLM. Creating a new regulatory definition could cause inconsistency and unnecessary confusion.

Recommended Revision:

> <u>*Person* means any individual, firm, corporation, association, partnership, consortium, or joint venture or entity, including a partnership, association, State, political subdivision of a State or territory, or a private, public, or municipal corporation.</u>

The proposed changes to the term "surface managing agency" are also problematic. The existing definition in § 3000.0-5 limits the definition to "any Federal agency *outside of the Department of the Interior* with jurisdiction over the surface overlying federally-owned minerals" (emphasis added). The proposed definition would expand the referenced federal entities to include "any Federal agency, other than the BLM, having management responsibility for the surface resources that overlay federally owned minerals." This would now include other DOI bureaus, for example, the U.S. Fish & Wildlife Service ("FWS") and the Bureau of Reclamation ("BOR"). Therefore, a legal problem with this definition is that it improperly expands the surface managing agency consent provisions of the Mineral Leasing Act for Acquired Lands ("MLAAL"), 30 U.S.C. § 352, which provides that "[n]o mineral deposit covered by this section shall be leased except with the consent of the head of the executive department, independent establishment, or instrumentality having jurisdiction over the lands containing such deposit . . . ." The FWS Director and the BOR Director are not heads of an executive department. Thus, BLM does not have the authority to delegate the MLAAL surface management responsibility for acquired lands to a DOI bureau official subordinate to the Secretary of the Interior (who is the head of the executive department) through this definitional change or otherwise.

Also, as explained below in relation to the changes to proposed § 3101.52, this proposed definitional change would improperly grant the FWS, BOR or other DOI bureau Director authority to block a Secretarial decision to lease federally-managed minerals. BLM therefore should not adopt the proposed change to the definition of "surface managing agency" in any final rule.

The Associations also refer to BLM to the comments below on proposed § 3120.42 utilizing the newly defined terms "acreage for which expressions of interest have been submitted" and "acres offered for lease."

B. § 3000.40 Appeals.

This proposed section would retain the provisions of existing § 3000.4 with minor revisions. However, this existing provision allowing adversely affected parties to appeal BLM leasing-related decisions to the Interior Board of Land Appeals ("IBLA") practically provides no appeal right because IBLA review generally takes several years.[16] The result is that the decision of the "authorized officer," defined in proposed § 3000.5 as "*any BLM employee* authorized to perform the duties prescribed in parts 3000 and 3100" (emphasis added), effectively becomes the final decision of the agency because by the time a leasing-related decision would reach the point for an IBLA determination, the issue in many instances could be moot. That is because within that multi-year IBLA appeal period, absent a stay granted by the IBLA, an appellant likely would need to comply with the challenged order or make other investments in its lease, and its primary lease term would continue to run. Therefore, as part of this regulatory update, BLM should utilize this opportunity to adopt a provision for State Director review similar to existing 43 C.F.R. § 3165.3(b) that allows adversely affected parties to promptly obtain BLM management level review from a decision of the "authorized officer." An adverse State Director decision then would be appealable to IBLA.

Recommended Revision:

> Except as provided in 43 CFR 3000.120, 3000.130, 3101.53(b), 3165.4, and 3427.2, any party adversely affected by a decision of

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[16] IBLA publishes a list of its pending appeals, https://www.doi.gov/oha/organization/ibla/IBLA-Pending-Appeals (as of July 31, 2023). There currently are several hundreds of pending appeals, many of which were filed in 2017, confirming that at the current rate it may take as long as seven years from when an appeal is filed with IBLA to receive a decision. Even if IBLA were able to cut its processing time for decisions by half, waiting that length of time effectively neutralizes any benefit to a prevailing appellant because later events may overtake an extant leasing dispute.

> the authorized officer made pursuant to the provisions of 43 CFR parts 3000 or 3100 has a right of appeal ~~pursuant to 43 CFR part 4~~. Any adversely affected party that contests an order or decision of the authorized officer issued under the regulations in parts 3000 and 3100 may request an administrative review before the State Director, either with or without oral presentation. Such request, including all supporting documentation, must be filed in writing with the appropriate State Director within 20 business days of the date such order or decision was received or considered to have been received and must be filed with the appropriate State Director. Upon request and showing of good cause, an extension for submitting supporting data may be granted by the State Director. Such review will include all factors or circumstances relevant to the particular case. Any party who is adversely affected by the State Director's decision may appeal that decision to the Interior Board of Land Appeals as provided in 43 C.F.R. part 4.

C. § 3000.60 Filing of Documents.

The Associations support BLM's proposal to allow for e-filing of necessary documents. However, to ensure that the appropriate official receives the e-filing, and to avoid any risk of default as a result of e-filing with the wrong person in a BLM office, or as a result of circumstances where a BLM employee may no longer be employed in that office, the final rule should require each BLM office to designate an email address for filing. An e-filing should be deemed timely if it is received by 11:59 pm local time in the appropriate BLM office. BLM should also ensure that its electronic systems are well-maintained and BLM provides sufficient training to operators utilizing electronic reporting. Some members of the Associations have experienced that BLM's electronic system frequently goes down, requires frequent changing of passwords, and presents other challenges.

Recommended Revision:

> All necessary documents must be filed in the proper BLM office. Documents may be submitted to the BLM using hard-copy delivery services, in-person delivery, or by electronic filing. A document will be considered filed when it is received in the proper BLM office. When using hard-copy delivery services or in-person delivery, the document will be considered filed only when received during regular business hours. See 43 CFR part 1820, subpart 1822. Each BLM office will establish an email address for acceptance of electronic filing that will be published on BLM's website, and electronic filing will be considered filed only when received by 11:59 pm local time in that BLM office.

D. § 3000.100 Fees in general.

For the reasons discussed below for proposed § 3000.120(a), BLM should revise proposed § 3000.100(c) to include the opportunity for notice and comment for adjustments to fixed fees established under this subchapter.

Recommended Revision:

> (c) Periodic adjustment. The BLM will periodically adjust fees established in this subchapter according to changes in the Implicit Price Deflator for Gross Domestic Product, which is published quarterly by the U.S. Department of Commerce. ~~Because the fee recalculations are simply based on a mathematical formula, t~~The BLM will change the fees in final rules ~~without~~ with the opportunity for notice and comment.

E. § 3000.120 Fee schedule for fixed fees.

This proposed section would add new fixed fees and increase existing fees for the listed processing and filing fees. The Associations generally support expansion of BLM's use of fixed fees as opposed to fees determined on a case-by-case basis. One exception is the $3,100 fee for a competitive lease application. BLM explains in the preamble that this fee was established as including the costs for BLM to undertake any necessary NEPA reviews. However, contrary to the preamble, nothing in CEQ regulations—existing or proposed—prohibits an applicant from preparing or assisting with the preparation of any BLM NEPA document, which would reduce BLM's costs. Therefore, the Associations suggest that the cost for a competitive lease application should be determined case-by-case under § 3000.110, or alternatively that the cost would be fixed at $3,100 but the applicant would have the option to request a case-by-case fee determination to establish a fee for a particular lease application. Such a situation would be, for example, where the NEPA or other costs to BLM would not support the $3,100 fee because the applicant will incur some or all of those costs separately.

Subsection (a) also would adjust the fixed fees annually "according to the change in the Implicit Price Deflator for Gross Domestic Product." The automatic inflation provision is contrary to the requirements for establishing these fees and should be removed. As BLM explains in the preamble, establishing these fees is a multi-factor process taking into account BLM's actual costs and other factors such as the monetary value of the right or privilege, the monetary value to the applicant, the efficiency factor, the public benefit factor, and the public service factor. BLM nowhere explains its authority to assume that any or all of these factors would justify an automatic annual adjustment based solely on inflation. Instead, to adjust a fixed fee, BLM must re-apply all of the factors, make a new determination as to whether the fee warrants an adjustment, and similarly codify that determination via rulemaking. Nor does BLM reference any other authority to impose this annual inflation adjustment.

In this subsection, BLM also states that it only would publish any fixed fee adjustment on BLM's website. As an initial matter, this is inconsistent with the provisions of proposed § 3000.100(c) which provide that for "fees established in this subchapter . . . BLM will change the fees in final rules . . . .” Additionally, because the fixed fees initially would be set by regulation, BLM must correspondingly amend any fixed fee through a regulatory change for it to have legal effect. BLM also should adopt any fixed fee adjustments through notice and comment rulemaking because the public should have the opportunity to address BLM’s application of the above-described factors in adjusting any fixed fee. Therefore, BLM should modify both §§ 3000.120(b) and 3000.100(c) to require notice and comment rulemaking to adjust any fixed fees in this subchapter of the regulations. For consistency and the convenience of the regulated community, BLM also should publish the updated fixed fees annually on its website.

The list of fees in Table 1 for § 3000.120 includes the “Expression of interest fee per acre or fraction thereof.” Section 50262(d) of the IRA amended the MLA to add a new 30 U.S.C. § 226(q) establishing a $5 per acre fee for expressions of interest in leasing available lands for exploration and development of oil and natural gas. New subsection 226(q)(2)(B) expressly authorizes the Secretary to adjust the $5 per acre fee “by regulation, not less frequently than every 4 years . . . to reflect the change in inflation.” Therefore, Congress requires that any adjustment to this fee be accomplished through regulation. BLM has no discretion to include a provision in proposed § 3000.120 allowing for an inflation adjustment for those fees through a website notification.

Recommended Revision:

> (a) The table in this section shows the fixed fees that must be paid to the BLM for the services listed for FY 2024. These fees are nonrefundable and must be included with documents filed under this chapter. BLM may adjust these fees periodically by final rule with the opportunity for notice and comment, and adjusted f~~F~~ees will ~~be adjusted annually according to the change in the Implicit Price Deflator for Gross Domestic Product since the previous adjustment and~~ ~~will subsequently~~ be posted on the BLM website (*https://www.blm.gov*) before October 1 each year. Revised fees are effective each year on October 1.

F. § 3000.130 Fiscal terms of new leases.

This section would establish per acre rental and bonus bid amounts. The fees established in the proposed rule are based on changes to the MLA required by the IRA, and the Associations agree that BLM has no discretion as to their adoption in this rulemaking. However, BLM also would provide in this section that the established rental rates and bonus bid amounts “will be adjusted annually according to the change in the Implicit Price Deflator for Gross Domestic Product since the previous adjustment and will subsequently be posted on the BLM website . . . before October 1 each year.” BLM does not have the authority to require these annual inflation adjustments. Section 50262(b)(1) of the IRA amends the MLA, 30 U.S.C. § 226(b)(1)(B), to set a minimum bonus bid of “$10 per acre during the 10-year period beginning on the date of enactment of the Inflation Reduction Act of 2022.” Nothing in the IRA authorizes an adjustment of the $10 minimum bid amount during that 10-year period, for inflation or otherwise. Under the MLA, “thereafter” the Secretary may establish by regulation a higher minimum bonus bid but only on certain specified grounds, namely when such increases are "necessary (i) to enhance financial returns to the United States; and (ii) to promote more efficient management of oil and natural gas resources on Federal lands." 30 U.S.C. § 226(b)(1)(B).

Similarly, Section 50262(c)(1) of the IRA amends the MLA, 30 U.S.C. § 226(d), to set per acre rental rates at prescribed levels for the 10-year primary term of the lease for leases issued after the IRA's effective date (August 16, 2022). Again, nothing in the IRA authorizes an adjustment of these rental rates for any reason, including for inflation, during the 10-year period.

Congress knows how to require inflation adjustments when it wants to, but did not do so here. As explained above, IRA Section 50262(d) amended the MLA to add a new 30 U.S.C. § 226(q) establishing a $5 per acre fee for expressions of interest in leasing available lands for exploration and development of oil and natural gas. New 30 U.S.C. § 226(q)(2)(B) expressly authorizes the Secretary to adjust the $5 per acre fee by regulation "to reflect the change in inflation." Also contrast the Federal Civil Penalties Inflation Adjustment Act of 2015, Public Law 114-74, sec. 701, in which Congress provided for inflation-based adjustments in civil penalty amounts. Thus, Congress knows how to provide for inflation adjustments when it so chooses, and it affirmatively chose not to allow inflation adjustments for the minimum bid and rental rates.

The Proposed Rule references no other authority that would support annual inflation adjustments for the rental and bonus fees. Indeed, even BLM acknowledged in the preamble that "[t]he IRA precludes the adjustment of these fiscal terms until after August 16, 2032." BLM thus has no discretion to include a provision in proposed § 3000.130 allowing for an annual inflation adjustment.

Recommended Revision:

> The table in this section shows the fiscal terms for new leases. ~~Terms will be adjusted annually according to the change in the Implicit Price Deflator for Gross Domestic Product since the previous adjustment and will subsequently be posted on the BLM website (*https://www.blm.gov*) before October 1 each year. Revised fees are effective each year on October 1.~~

II. PART 3100

A. § 3100.5 Definitions.

This section of the Proposed Rule would add several new definitions. The Associations agree with most of the revised definitions, but there are a few that BLM should change in any final rule.

BLM would define the term "modification" as "a change to the provisions of a lease stipulation for some or all sites within the leasehold and either temporarily or for the term of the lease." However, BLM uses the term in other contexts of the Proposed Rule. For example, § 3101.12 Surface use rights, provides (emphasis added):

> A lessee will have the right to use only so much of the leased lands as is necessary to explore for, drill for, mine, extract, remove and dispose of all the leased resource in a leasehold subject to applicable requirements, including stipulations attached to the lease, restrictions deriving from specific, nondiscretionary statutes, and such reasonable measures as may be required and detailed by the authorized officer to avoid, minimize, or mitigate adverse impacts to other resource values, land uses or users, federally recognized Tribes, and underserved communities. Such reasonable measures may include, but are not limited to, relocation or *modification* to siting or design of facilities, timing of operations, specification of interim and final reclamation measures, and specification of rates of development and production in the public interest. *Modifications* that are consistent with lease rights include, but are not limited to, requiring relocation of proposed operations by more than 800 meters and prohibiting new surface disturbing operations for a period of up to 90 days in any lease year.

In addition, subsection (b) of § 3140.23 Application requirements, provides (emphasis added):

> (b) A plan of operations may be *modified* or amended before or after conversion of a lease or valid claim to reflect changes in technology, slippages in schedule beyond the control of the lessee, new information about the resource or the economic or environmental aspects of its development, changes to or initiation of applicable unit agreements or for other purposes. To obtain approval of a *modification* or amended plan, the applicant must submit a written statement of the proposed changes or supplements and the justification for the changes proposed. Any *modifications* will be in accordance with 43 CFR 3592.1(c). The approval of the *modification* or amendment is the responsibility of the authorized officer. Changes or *modification* to the plan of operations will have no effect on the primary term of the lease. The authorized officer will, prior to approving any amendment or *modification*, review the *modification* or amendment with the appropriate surface management agency. For leases within units of the National Park System, no amendment or *modification* will be approved without the consent of the Regional Director of the National Park Service in accordance with § 3140.70.

Finally, § 3141.22 Exploration licenses, provides in subsection (c)(2) (emphasis added) that "[t]he authorized officer may require *modification* of the original exploration plan to accommodate the legitimate exploration needs of the person(s) seeking to participate and to avoid the duplication of exploration activities in the same area, or that the person(s) should file a separate application for an exploration license." Subsection (e)(8) further provides that (emphasis added):

> The licensee may submit a request for *modification* of the exploration plan to the authorized officer. Any *modification* will be subject to the regulations in this section and the terms and conditions of the license. The authorized officer may approve the *modification* after any necessary adjustments to the terms and conditions of the license that are accepted in writing by the licensee.

Because the regulations in part 3100 use the term "modification" in contexts other than changes to lease stipulations, to avoid confusion BLM should remove the proposed definition.

BLM should modify the proposed definition of "Oil and gas agreement" because an agreement may in some instances include unleased lands. In those circumstances, the operator typically may place the production proceeds into an interest-bearing escrow account until the lands are leased.

Recommended Revision:

> *Oil and gas agreement* means an agreement between lessees and the BLM to govern the development and allocation of production for existing leases <u>and unleased lands</u>, including, but not limited to, communitization agreements, unit agreements, secondary recovery agreements, and gas storage agreements.

BLM is proposing to add new definitions for the terms "responsible bidder" and "responsible lessee." Each of these terms would exclude a person who has a "history of noncompliance" with applicable regulations and lease terms. These terms are used in proposed § 3102.51 Compliance, which provides that "[o]nly responsible and qualified bidders may own, hold, or control an interest in a lease or prospective lease." The Associations have substantial concerns with these definitions because it is unclear what a "history of noncompliance" means. It could be construed broadly to mean that if a person ever was found to have been in noncompliance with its federal oil and gas lease terms, or applicable BLM regulations or ONRR royalty reporting and valuation regulations in 30 C.F.R. part 1206, it could be precluded from obtaining future federal lease interests, even if it corrected the alleged noncompliance after notice from the regulatory agency. Similarly, it is unclear how these definitions would be applied to extant claimed noncompliance with regulations or lease terms that are under appeal to the agency or the IBLA and are either subject or not subject to a stay under 43 C.F.R. § 4.21 or other applicable regulations. Under the Proposed Rule, those persons too could be disqualified from obtaining future federal oil and gas lease interests. Nor does the preamble provide any explanation of what BLM intends by the phrase "history of noncompliance."

BLM also proposes to add a new definition of "qualified lessee" as a "person in compliance with the laws and regulations governing the BLM issued leases held by that person." The Associations have the same concerns with this definition, as well as with the related definition of "qualified bidder," because they again are unclear whether any regulatory or lease noncompliance (or allegation thereof), even a minor one, could render a person unqualified to hold federal onshore leases. Moreover, the definition of "qualified bidder" does not account for the involvement of brokers or non-operating partners when bidding on leases, and could substantially impede bidding if it were to mandate established bonding in place prior to bidding or similar other requirements.

Please also see the Associations' comments on proposed § 3102.51 and its scope of "responsible and qualified bidders and lessees." To allay these concerns, BLM should clarify in this proposed definitions section and in proposed § 3102.51 that it will continue to adhere only to the factors in MLA Section 17(g), 30 U.S.C. § 226(g), in determining who may hold a lease.

BLM is proposing to add definitions of the terms "assignment" and "transfer" that would have corresponding, but different, meanings. BLM's sister bureau, the Bureau of Ocean Energy Management ("BOEM"), recently issued a proposed rule stating that the terms "transfer" and "assignment" are "interchangeable." Risk Management and Financial Assurance for OCS Lease and Grant Obligations, 88 Fed. Reg 42,136, 42,149, 42,151, 42,169 (June 29, 2023). BLM should ensure consistency and clarity in use of these terms between the two bureaus regulating federal oil and gas leasing onshore and on the Outer Continental Shelf.

B. § 3100.22 Drilling and production or payment of compensatory royalty.

This section is unchanged from the corresponding existing section. BLM should consider using this rulemaking opportunity to amend this section to also address circumstances involving two federal leases with different fund distribution codes. For example, such a situation may involve a MLA lease with a royalty revenue distribution governed by 30 U.S.C. § 191(a) being drained by a well on an MLAAL lease with a different royalty revenue distribution that allocates a higher proportion of funds to non-federal recipients based on the provisions of the statute pursuant to which the lands were acquired. This regulation also should reference the lessee's opportunity to create a federally-approved agreement for sharing of production among the affected leases.

Recommended Revision:

> Where lands in any leases are being drained of their oil or gas content by wells either on a Federal lease issued at a lower rate of royalty or on non-Federal lands, or by a lease with a different royalty revenue funds distribution requirement, the lessee must both drill and produce all wells necessary to protect the leased lands from drainage. In lieu of drilling necessary wells, the lessee may, with the consent of the authorized officer, pay compensatory royalty in the amount determined in accordance with 43 CFR 3162.2–4, or under an oil and gas agreement among the affected leases and tracts.

C. § 3100.40 Public availability of information.

In the preamble, BLM states that it is considering making publicly available names and addresses of the nominator, lessees, operating rights holders and operators through BLM's automated system, and that such information is already publicly available. BLM provides no justification for publishing information on all entities registered to bid during a lease sale, rather than only information regarding issued leases.

D. § 3101.12 Surface use rights.

The proposed changes to this section are extremely concerning to the Associations and their members because they improperly broaden BLM's authority to impose limitations on the exercise of lease rights. It is well-established that the issuance of a federal onshore oil and gas lease entitles the lessee to develop its lease subject to only limited, reasonable restrictions. *Conner v. Burford,* 848 F.2d 1441 (9th Cir. 1988). That is, consistent with the MLA, BLM cannot wholly prevent lessees from engaging in all surface-disturbing activities necessary for mineral development, except where the lease it issues states otherwise, principally in a no-surface-occupancy provision. Consistently, courts typically find that onshore federal leasing is the point that results in an irretrievable commitment of resources for oil and gas development, effectively eliminating the no action alternative and generally requiring more detailed environmental review prior to lease issuance onshore compared to earlier stages onshore or leasing offshore.[17]

Yet, the Proposed Rule risks precluding development of existing leases at odds with rights already conferred under those contracts. That is because the proposed new limitations on the lessee's ability to exercise its lease rights would be so restrictive that the development rights which a MLA or MLAAL federal oil and gas lease has historically granted could be rendered effectively illusory. The redrafted section would subject use of leasehold lands for oil and gas operations to "applicable requirements" that would include "such reasonable measures as may be required by the authorized officer to avoid, minimize, or mitigate adverse impacts to other resource values, land uses or users, federally recognized Tribes, and underserved communities." The terms "avoid" and "mitigate" are newly-added and undefined limitations. These rights reserved to BLM are so broad, vague, and subjective that they could empower BLM to significantly constrain or entirely prevent operations on the leasehold. If the lessee objects, its

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[17] *See, e.g., id.* at 1451; *New Mexico ex rel. Richardson v. Bureau of Land Mgmt.*, 565 F.3d 683, 718 (10th Cir. 2009) (lessee "cannot be prohibited from surface use of the leased parcel once its [non-no surface occupancy ("NSO")] lease is final"); *see also Pennaco Energy, Inc. v. U.S. Dep't of the Interior*, 377 F.3d 1147, 1160 (10th Cir. 2004) (the lease provided lessees with certain rights and did not give the federal government the authority to deny drilling activity); *Sierra Club v. Peterson*, 717 F.2d 1409, 1412, 1415 (D.C. Cir. 1983) (BLM must either prepare an Environmental Impact Statement before leasing or "retain the authority to preclude surface disturbing activities until an appropriate environmental analysis is completed"); *Ctr. for Biological Diversity v. BLM*, 937 F. Supp. 2d 1140, 1153 (N.D. Cal. 2013) (non-NSO leases required environmental analysis prior to issuance even though they contained provisions allowing BLM to deny all surface disturbing activities if threatened or endangered species are found); Bureau of Land Mgmt., U.S. Dep't of the Interior, BLM Manual H-1624-1 Planning for Fluid Mineral Resources, at I-2 (1990), https://www.blm.gov/sites/blm.gov/files/uploads/Media_Library_BLM_Policy_Handbook_H_1624_1.pdf ("By law, these impacts must be analyzed before the agency makes an irreversible commitment. In the fluid minerals program, this commitment occurs at the point of lease issuance.").

only recourse under the rules would be to challenge the BLM decision through an administrative appeal—with no certainty that its lease term would be suspended in the interim. And unless BLM amends the appeal regulation as the Associations suggest to first allow for State Director review, that appeal process would inexorably last several years.

BLM asserts in the preamble that these authorities inserted into this section are consistent with the standard BLM lease form since 2008. However, as BLM further explains in the preamble, "[t]he standard lease form authorizes the BLM to require 'reasonable measures' to the extent such measures would be consistent with the lessee's rights." The BLM lease form also does not subordinate the oil and gas lessee's rights to any subsequently issued right for other uses or users; rather, it does the opposite. *See* BLM Form 3100-11 (March 2023), ¶ 6 ("Lessor reserves the right to continue existing uses and to authorize future uses upon or in the leased lands, including the approval of easements or rights-of-way. Such uses must be conditioned so as to prevent unnecessary or unreasonable interference with rights of lessee."). BLM references no lease provision that grants the agency the proposed new broad authority to severely constrain or deny lease operations to the extent set forth in the Proposed Rule.

Under this section, BLM also proposes to allow altering the location of a well by "more than 800 meters." That means there would be no limit to how far BLM may require relocation of a well on a lease, and BLM has provided no data or other scientific justification to support what relocation distance is appropriate. In fact, though BLM's preamble summarily asserts "changes in technology" to support the proposed changes, it provides no technical justification.

The existing rule provides that BLM may not require relocation of a well by more than 200 meters.[18] 43 C.F.R. § 3101.1-2. Thus, the Proposed Rule arbitrarily replaces a maximum provision with an unlimited provision. Moreover, it could very well prohibit on-lease surface use and require surface activities, like drilling, to occur at an off-lease surface location (e.g., the Proposed Rule would unreasonably delete the existing regulatory prohibition on BLM requiring that "operations be sited off the leasehold"). *Id.* Precluding on-lease surface use impermissibly deprives a lessee of a vested right to develop its minerals, potentially constituting a taking of a lessee's property right. Additionally, well placement is typically based on geology, topography, and surface owner requirements (including wildlife, cultural, wetland, and similar issues that inform the well placement). BLM also fails to explain what rights BLM or a lessee may have to locate wells or facilities off-lease, particularly when other tracts may be held by different entities.

Accordingly, the Proposed Rule should be modified to establish a *maximum* allowable relocation distance based on scientific data justifying the decision, and to prohibit relocation to an off-lease location without the lessee's prior consent. Also, at a minimum, BLM's ability to move a well location must not result in a loss of maximum efficient recovery of oil or natural gas; add significant costs; or materially change access routes, surface disturbance, or availability of utilities or infrastructure compared to a lessee's chosen surface location. BLM regulations

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[18] BLM claims that despite the existing regulations' clear 200 meter maximum, the IBLA held in *Yates Petroleum,* 176 IBLA 144, 156 (2008), that BLM may impose greater restrictions. But *Yates* did not confer on BLM the unbounded authority reflected in the Proposed Rule, or bless any BLM-imposed limitation, including based on the Proposed Rule's plethora of novel and subjective criteria, as "reasonable" or "consistent with lease rights."

should not support waste of oil and gas resources, nor should they provide a basis for BLM to contravene the lease contract.

Moreover, BLM is proposing to change the annual period for which it may prohibit new surface disturbing operations from 60 days to 90 days, with no justification for that proposed change. This extension is too long and is unwarranted. For example, depending on how BLM applies these prohibition windows, they may result in even longer inoperative periods due to weather conditions, wildlife considerations, natural processes, and economic factors during the remaining calendar year. BLM should not adopt this modification to the existing rule.

To the extent BLM would seek to apply the regulatory changes it is proposing to allow the agency to constrain or prevent operations on existing leases, it presents a material breach of contract or a regulatory taking, potentially subjecting the United States to substantial contract damages or payment of just compensation.[19] Breach and takings concerns for existing leases are especially salient given the development rights conferred by onshore federal oil and gas leases under the MLA and interpretive case law, as discussed above. The Proposed Rule would significantly alter standards in place at the time existing leases were bargained for, by imposing substantial costs and burdens on lessees, or even precluding or terminating production.[20] At a minimum, proposed § 3101.12 and other Proposed Rule provisions purporting to materially curtail existing lease rights would do so. The Proposed Rule's language does not even limit the timing for imposing surface use restrictions under this section. For example, it could be read to allow imposition of such conditions during or after construction of wells or facilities on a lease. Or it could be interpreted to require later drilled wells to utilize different, more distant facilities than earlier APDs approved without such setbacks or other conditions. Accordingly, BLM is incorrect in determining "that the rule would not cause a taking of private property or require further discussion of takings implications under Executive Order 12630." BLM should not adopt proposed provisions that would allow for such potential breach or takings, and must provide a more complete analysis of why its final rule would not do so.

E. § 3101.13 Stipulations and information notices.

The Associations are again very concerned about the proposed changes to the existing regulations in this section. Proposed new subsection (a) would give BLM broad authority to "consider the sensitivity and importance of potentially affected resources," and any "uncertainty concerning the present or future condition of those resources," and then based on this highly subjective and amorphous standard, consider "whether a resource is adequately protected by stipulation *without regard for the restrictiveness of the stipulation on operations*" (emphasis added). This subsection would allow BLM to offer for lease lands that are eligible and available

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[19] *See Mobil Oil Prod. Southeast, Inc. v. U.S.*, 530 U.S. 604 (2000); *Amber Res. Co. v. U.S.*, 68 Fed. Cl. 535 (2005).

[20] *See Marathon Oil Co. v. Andrus*, 452 F. Supp. 548, 551 (D. Wyo. 1978) (invalidating BLM's former NTL-4, and finding: "This Court cannot lose sight of the general rule that, when the executive department charged with the execution of a statute gives a construction to it and acts upon that construction for many years, the Court looks with disfavor upon a change whereby parties who have contracted in good faith under the old construction may be injured by a different interpretation.").

for leasing, but then subject the offered leases to additional stipulations that could restrict operations to the point that they are uneconomic or infeasible to undertake.

Providing BLM with unfettered discretion to impose lease stipulations that constrain or effectively prevent operations would severely undermine the value of those leases and discourage entities from bidding on those leases due to the resulting investment uncertainty. Yet, per BLM, the acreage purportedly offered for lease would contribute to fulfilling the IRA's minimum acreage criteria to allow BLM to issue rights-of-way for wind and solar energy development on federal lands. Thus, the addition of this subsection provides an avenue for BLM to technically meet the oil and gas acreage offered for lease required by IRA Section 50265 as necessary for BLM to issue wind and solar rights-of-way, while from a practical standpoint potentially discouraging leasing or constraining opportunities to develop minerals on federal lands. This new proposed subsection (a), together with the proposed changes in § 3101.12, make federal oil and gas lease development rights far less predictable, reliable, and practical, and therefore would significantly undermine the value to operators. Thus, in any final rule, BLM should remove subsection (a) in its entirety. At a minimum, BLM should remove the final clause of subsection (a) ("without regard for the restrictiveness of the stipulation on operations")—and instead require that all stipulations applicable to specific leases/parcels be disclosed prior to a lease sale, and appropriately circumscribe BLM's discretion to impose lease stipulations to not frustrate efficient and orderly federal leasing or development of leasehold rights.

F. § 3101.14 Modification, waiver, or exception.

Subsection (b) presents potential disruption to the competitive lease sale process. Under these new provisions, if following a lease sale, but prior to lease issuance, BLM determines it needs to add an additional restrictive stipulation, the winning bidder is given an opportunity to refuse the stipulation and the BLM may reject the bid. Also, if after a lease sale is concluded BLM adds or modifies a stipulation that increases the value of the parcel, BLM will reject the bid and include the parcel in the next competitive lease sale. These provisions inject uncertainty into the competitive leasing process and inappropriately allow BLM to "reopen" the lease conditions in a manner that may very well impact the value of the lease to the winning bidder. Again, at a minimum, all lease conditions or stipulations must be disclosed prior to a lease sale. Once a competitive lease sale is held, and competitors to the winning bidder are aware of the per acre amount the winning bidder was willing to pay to obtain a lease tract, allowing BLM to "undo" the lease sale and re-bid the tracts is anticompetitive and unfair to the winning bidder. BLM also could improperly use this provision as a tool to undo a lease sale where it is dissatisfied with the result of the competitive sale by unilaterally imposing a new stipulation with no opportunity for public involvement, which is inconsistent with subsection (a)'s requirement that BLM involve the public in any change to a lease term or stipulation. BLM's only support for these new provisions is a preamble assertion that they purportedly are consistent with existing "policy," but BLM does not identify the source of that policy or how it has been applied.

BLM also is proposing to remove the language from existing § 3101.1-4 that allows BLM to grant waivers, modifications, or exceptions if "proposed operations would not cause unacceptable impacts." BLM asserts this provision has been overused and resulted in adverse impacts. Yet, the Proposed Rule does not recognize the host of reasonable circumstances where flexibility under the existing provision does not result in unacceptable impacts (see below paragraph). BLM should not remove this flexibility available to BLM field offices without providing evidence of these purported adverse impacts and then establishing appropriate limits on this flexibility if necessary to narrowly address those specific adverse impacts. Nor can BLM in its preamble credibly dismiss this existing standard as "very subjective" when its Proposed Rule would introduce a bevy of more subjective standards.

Moreover, BLM's proposed narrowing of § 3101.14 will be very detrimental to real-time operations and could cause serious health, safety, and environmental consequences. The kinds of actions that warrant waivers, modifications, or exceptions usually are time sensitive and require real-time data that is evaluated by qualified individuals, such as immediate downhole drilling changes or wildlife stipulation relief based on a 2-week window of field nest evaluations. Other waivers, modifications, or exceptions are needed due to technological advances (e.g., flexhose and Coriolis meters). Thus, BLM should preserve the flexibility in the existing regulation.

G. § 3101.21 Public domain lands.

The text of subsection (a) should reference that the acreage limit in this section is only for federal leases on public domain lands. BLM should not rely only on the section title.

Recommended Revision:

> No person may take, hold, own or control more than 246,080 acres of Federal oil and gas leases <u>on public domain lands</u> in any one State at any one time. No more than 200,000 acres of such acres may be held under option.

H. § 3101.22 Acquired lands

The text of subsection (a) should reference that the acreage limit in this section is for federal leases on acquired lands. BLM should not rely only on the section title.

Recommended Revision:

> (a) No person may take, hold, own or control more than 246,080 acres of Federal oil and gas leases <u>on acquired lands</u> in any one State at any one time. No more than 200,000 acres of such acres may be held under option.

I. § 3101.51 General Requirements.

This proposed section would provide that "[p]ublic domain and acquired lands will be leased only with the consent of the surface managing agency . . . ." The Associations have significant concerns with the proposed changes to this section.

BLM explains in the preamble that this proposed section would combine subsections (a), (b), and (c) of existing § 3101.7-1 applicable to acquired lands, public domain lands, and National Forest System lands, respectively. However, this proposed section would grant surface managing agencies expanded authority beyond that which is provided under applicable statutes and the existing rules to veto acreage for federal oil and gas lease sales. It also would expand the scope of federal entities that would be authorized to exercise that "veto" authority because of BLM's proposed revision to the definition of "surface managing agency" in § 3000.5 improperly expanding that term to include DOI bureaus.

Only part of this proposed regulation is consistent with applicable requirements. Surface management agency consent is statutorily required for BLM to lease oil and gas beneath acquired lands under the MLAAL (30 U.S.C. § 352, requiring consent of "the head of the executive department . . . and subject to such conditions as that official may prescribe . . . ."). Thus, for example, if the minerals beneath a National Forest are acquired minerals, BLM may not lease the oil and gas without the consent of the Secretary of Agriculture.

However, there is no corresponding general statutory consent provision under the MLA for leasing oil and gas on public domain lands other than national forests (*see* 30 U.S.C. § 226(f)), and current regulations do not grant such expansive authority. Recognizing this non-existent statutory consent authority for public domain lands, existing § 3101.7-1(b) provides that BLM may not lease public domain lands unless it has "consulted" with the surface managing agency (defined in existing § 3000.0-5(m) as "any Federal agency *outside* of the Department of the Interior with jurisdiction over the surface overlying federally-owned minerals"), and the surface managing agency has "reported its *recommendations* to lease with stipulations, if any, or not to lease to the authorized officer" (emphasis added). Existing § 3101.7-1(b) provides that BLM may proceed to lease unless "consent or lack of objection of the surface managing agency is required by statute." Thus, the consultation/recommendation standard under the existing rules does not equate to an absolute consent role. In the absence of general statutory consent authority, which the Proposed Rule nowhere identifies, BLM does not have the authority to delegate to another federal agency the Secretary's authority to decide which public domain lands should be offered for lease.

Also concerning to the Associations and their members regarding implementation of this proposed section is that, as explained above, proposed § 3000.5 would expand the definition of "surface managing agency" to include not only federal Departments, but also DOI bureaus. Read together, proposed §§ 3101.51 and 3000.5 would grant FWS, BOR or other DOI bureaus authority to prevent leasing of acquired minerals beneath lands they administer even though they are not an "executive department" under the MLAAL. Proposed § 3101.51 also would provide DOI bureaus veto authority for public domain lands leasable under the MLA—even if BLM, or the Secretary, wanted to lease the parcels. While the Secretary oversees subordinate DOI agencies, it is well-established that all DOI agency officials, including the Secretary, would be bound by a duly promulgated regulatory provision diminishing the Secretary's ultimate leasing authority. *Vitarelli v. Seaton*, 359 U.S. 535, 539-40 (1959); *United States v. Nixon*, 418 U.S. 683, 696 (1974). BLM therefore should remove this proposed section purporting to convey to DOI bureaus this expanded authority to prevent leasing of federal minerals.

Recommended Revision:

> ~~Public domain and a~~Acquired lands will be leased only with the consent of the surface managing agency [with amended definition in § 3000.5 to include only non-DOI agencies]~~,~~. ~~which,~~ BLM will

> require the consent of the surface managing agency for public domain lands only if there is a statutory requirement for such consent. ~~u~~Upon the surface managing agency's receipt of a description of the lands from the authorized officer, it will report to the authorized officer that it consents to leasing with stipulations, if any, or withholds consent or objects to leasing.

J. § 3101.52 Action by the Bureau of Land Management.

The Associations have the same concerns with this section of the Proposed Rule as with its immediately preceding section. Proposed § 3101.52(b) provides that "[t]he authorized officer will not issue a lease on lands to which the surface managing agency objects or withholds consent." Like § 3101.51, this subsection means that regardless of whether the lands are acquired or public domain lands, the BLM will not lease lands when a surface management agency objects to leasing or withholds its consent. This is an improperly broad veto authority granted to surface managing agencies for public domain lands, and like the previous section suffers from the excessively broad definition of the term "surface managing agency" for acquired lands. BLM should not extend this authority to preclude leasing of public domain lands except for circumstances where the surface managing agency has statutory consent authority.

Recommended Revision:

> (b) The authorized officer will not issue a lease on acquired lands, or for other lands for which the surface managing agency has statutory authority to consent to leasing, to which the surface managing agency objects or withholds consent. In all other instances, the Secretary has the final authority and discretion to decide to issue a lease.

K. § 3101.53 Appeals.

As explained above regarding proposed § 3000.40, this existing provision providing adversely affected parties an appeal to the IBLA from BLM decisions relating to rejection of offers to lease, or to issue a lease with stipulations recommended by the surface managing agency, effectively eviscerates any appeal right because IBLA review generally takes several years. Therefore, as part of this regulatory update, BLM should amend this section to include State Director review, with the option to further appeal to IBLA.

Recommended Revision:

> ~~The~~ Any person adversely affected by a decision of the authorized officer to reject an offer to lease or to issue a lease with stipulations recommended by the surface managing agency, may request an administrative review before the State Director, either with or without oral presentation. Such request, including all supporting documentation, must be filed in writing with the appropriate State Director within 20 business days of the date such order or decision was received or considered to have been received and must be filed with the appropriate State Director. Upon request and showing of good cause, an extension for submitting supporting data may be granted by the State Director. Such

review will include all factors or circumstances relevant to the particular case. Any party who is adversely affected by the State Director's decision may appeal that decision ~~may be appealed~~ to the Interior Board of Land Appeals under 43 CFR part 4.

L. § 3102.51 Compliance.

Under this section, "[o]nly responsible and qualified bidders and lessees may own, hold, or control an interest in a lease or prospective lease." The Associations explained their concerns with the definitions of these terms in their comments above on proposed § 3100.5. The Associations have further concerns with this section because it requires that the person be in compliance with multiple subsections that, in turn, reference other statutory and regulatory provisions. In particular, subsection (f) of this section appears to unreasonably disqualify persons from holding federal lease interests, and to unlawfully subject existing leases to cancellation.

Under this subsection (f), adopted to implement 30 U.S.C. § 226(g), a signature on an offer, lease, assignment, or transfer constitutes evidence of compliance that the signatory and any of its affiliates has not failed to comply with reclamation requirements with respect to all leases and operations on those leases in which such person has an interest. The proposed subsection would modify the existing regulations by providing that BLM may find persons noncompliant when they purportedly fail to comply with reclamation obligations in the time specified in a "notice from the BLM," rather than after BLM takes additional enforcement steps such as issuing a written order, an Incident of Noncompliance ("INC"), or a civil penalty. Despite eliminating from the existing subsection the need for BLM to take these additional enforcement steps, the proposed subsection would carry over the provision from the existing rule that "any such person in violation of this paragraph (f) will be subject to the cancellation provisions of 43 CFR 3108.30, notwithstanding any administrative or judicial appeals that may be pending with respect to violations or penalties assessed for failure to comply with the prescribed reclamation standards on any lease holdings." The effect of this new provision is that if you receive notice from BLM asserting that you or any of your affiliates has an unfulfilled reclamation obligation (regardless of accuracy of the assertion) for any federal oil and gas lease, and you in good faith challenge that determination administratively, BLM may proceed to cancel your leases while the appeal is pending unless you fulfill the claimed reclamation deficiency. This is unreasonable restructuring of the existing subsection and will result in a denial of due process by effectively mooting any appeal opportunity.

Moreover, the newly proposed sentence in subsection (f) would expand the scope of this subsection from only "reclamation" requirements to also encompass "other standards established under 30 U.S.C. 226." Indeed, the other sentences of subsection (f) would continue to refer only to "reclamation." This unwarranted expansion would only exacerbate the lease cancellation concerns discussed above.

BLM should not adopt the proposed changes to this section in the final rule, and instead adhere to the terms of existing 43 C.F.R. § 3102.5–1.

Subpart 3103.

In its preamble, BLM asks for comment on whether it should adopt a 5-year diligent development requirement, and a rental increase if diligent development requirements are not met. BLM should not. These new diligent development terms would impose large cost increases on a substantial number of leases. They also would not allow the operator flexibility to properly evaluate and commence operations in a responsible developmental situation and economic manner consistent with lease requirements. Federal leases include terms, such as the recently increased rental fees, that already incentivize prudent development or lease surrender.

New diligent development requirements also are unnecessary because in the IRA Congress amended the MLA to establish new escalating minimum rental requirements to spur diligent development of federal leases. First, IRA Section 50262(c) amends 30 U.S.C. § 226(d) to permanently increase the prior minimum rental rate from $1.50 per acre per year for the first through fifth years, and not less than $2 per acre per year thereafter, to "$3 per acre per year during the 2-year period beginning on the date the lease begins for new leases, and after the end of that 2-year period, $5 per acre per year for the following 6-year period, and not less than $15 per acre per year thereafter. . . ." That section then provides that "in the case of a lease issued during the 10-year period beginning on the date of enactment of the Inflation Reduction Act of 2022, $3 per acre per year during the 2-year period beginning on the date the lease begins, and after the end of that 2-year period, $5 per acre per year for the following 6-year period, and $15 per acre per year thereafter." Consequently, until 2032, Congress has considered the diligent development issue and increased rental rates as prescribed in IRA Section 50162, and BLM has no discretion to alter those rates by rule. For the period beginning in 2032, it is premature for BLM to consider whether to escalate what would then become the same level of prescribed minimum rental rates, which already are much higher than pre-IRA rates. Instead, BLM should wait to assess the status of the federal oil and gas leasing regime and related market dynamics until closer to 2032.

The Proposed Rule also ignores the obstacles often placed by regulatory agencies and others that have the consequence of delaying development for reasons beyond the lessee's control after a lease is issued. As a result, it would not be appropriate for BLM to impose any other diligent development requirements at this time.

M. § 3103.31 Royalty on production.

This section properly recognizes that the royalty rate increases prescribed in IRA Section 50262(a)(1) do not apply to existing leases with lower royalty rates. The Associations note that BLM thus must be prepared to respond to increased requests for surface commingling approvals and other consequences of neighboring leases with disparate royalty rates.

N. § 3103.42 Suspension of operations ["SOO"] and/or production ["SOP"]; § 3165.1 Relief from operating and/or producing requirements.

The Proposed Rule, like existing 43 C.F.R. § 3103.4–4(a), would allow a suspension "of all operations and production" "only in the interest of conservation of natural resources," and would require a "SOO only" or a "SOP only" request to show "*force majeure.*" BLM should take the opportunity in this rulemaking to instead broaden eligible circumstances for an SOO or SOP beyond *force majeure*, or at a minimum should acknowledge that BLM's own delays constitute such *force majeure* for purposes of an SOO or SOP. Doing so would afford flexibility regarding suspensions, where warranted, based on individual circumstances. The Proposed Rule fails to explain the existing limitations, or to cite to or harmonize BLM's recent IM 2023-012 addressing the grounds and process for a lease SOO or SOP.[21] BLM also must reconcile the proposed new § 3165.1(c) and IM 2023-012—both of which would newly foreclose suspensions based on an APD filed less than 90 days before lease expiration—with agency policy against premature suspensions, and with the reality of BLM's own delays in processing APDs and suspensions, so that lessees can clearly understand the appropriate timing for submitting and adjudicating APDs and requests for suspensions.

O. § 3104.10 Bond Obligations

BLM should retain Certificates of Deposit ("CDs") and Letters of Credit ("LOCs") as forms of security for personal bonds. The Proposed Rule's stated rationale for removing these options is that CDs are difficult to manage and it is difficult for banks to include BLM's requirements in a LOC. However, BLM provides no information on how often this occurs, what type of operators (small or large) use CDs and LOCs, and other similar details on the issue. At a minimum, BLM should provide an analysis of this issue for review and comment before removing such options. As a general matter, and as further explained in the Associations' comments below on proposed § 3104.50, BLM should afford greater—rather than less—flexibility to operators regarding forms of security, particularly given the Proposed Rule's drastically higher minimum and additional bond amounts.

P. § 3104.20 Lease bond.; § 3104.30 Statewide bonds.

The Associations support the principle that existing lease interest owners and their operator should be responsible for fulfilling all lease obligations, including decommissioning. This is not a burden that should be placed on predecessor interest owners that may have assigned away their lease interest years, or even decades, ago. Nor is it a burden that should fall on the American taxpayer when there is no predecessor in interest. However, BLM should ensure that its financial assurance requirements for existing interest owners and operators are applied sensibly and fairly.

The Proposed Rule's increases in bonding amounts for lease ($150,000) and statewide ($500,000) bonds are excessive, and likely will result in premature termination of operations and corresponding waste of federal resources. While the Proposed Rule's preamble cites draft bills that led to the IRA in proposing corresponding minimum bonding amounts, Congress ultimately did *not* enact those minimums. *See* 88 Fed. Reg. at 47,581. BLM's economic justification fails to account for circumstances of individual leases that have been in effect for years if not decades. This is particularly concerning for leases nearing the end of their productive life, because BLM's imposition of 15-to-20 fold increases of lease and statewide bonding obligations on such leases could be expected to result in premature shut-in and abandonment, leaving otherwise producible oil and gas resources in the ground. These bonding changes will be particularly impactful to

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[21] https://www.blm.gov/policy/im-2023-012.

smaller operators with less financial wherewithal to obtain such increased bonding or pay associated premiums. Therefore, BLM should consider reducing the proposed minimum bond amounts, or alternately providing for accommodations to existing leases unable to feasibly satisfy the dramatically increased minimum bond amounts.

BLM should modify § 3104.20 of the Proposed Rule because it is inconsistent with other sections of the Proposed Rule and is confusing. For example, under proposed § 3104.10, before any surface disturbing activities, the lessee, operating rights owner *or* operator would have to submit a surety bond or personal bond for the amounts required in subpart 3104. However, proposed § 3104.20 then inconsistently limits what is permitted under proposed § 3104.10 by providing that "[t]he operator must be covered by a bond in its own name as principal or obligor in an amount of not less than $150,000 for each lease . . . ." BLM claims in the preamble that this change is intended to simplify bonding requirements among the operator, lessee, and operating rights holder. However, BLM fails to appreciate that as a result of the substantial minimum bond amount increases that now would be incorporated into this section, this new operator bonding requirement would put a large financial burden on operators of multiple leases, particularly if they are operating on federal leases in several different states. For example, for an operator with 10 federal leases each in a different state, this proposed change would increase the bond obligation from $100,000 under the existing rules to $1.5 million as a result of the per lease bond amount increase required under this Proposed Rule. BLM's primary concern should be that at least one person must post the required financial assurance for a lease, and should leave it to the operator, lessee, and operating rights owner to determine among themselves who will provide the required bonding for a particular lease.

This proposed section further would provide that "[a]dditional bonding may be posted by a lessee, or owner of operating rights," with no further clarification in the regulatory language or the preamble as to what additional bonding obligation this section is referring to. If BLM is referring to supplemental bonding under § 3104.50(b), then it should clarify the rule accordingly. However, if it is a reference to supplemental bonding, then BLM is creating a potential problem if the operator fails to comply with a lease obligation. It would be uncertain whether BLM must first make a claim against the operator's security, or whether BLM could choose instead to make an initial claim against the supplemental financial assurance posted by the lessee or sublessee. These are financial issues that are better left to the lease interest owners and the operators to allocate and not for BLM to dictate through rulemaking. Again, BLM's primary concern should be that it is provided with adequate financial assurance to meet the lease obligations, and not which person provides the base bonding or the supplemental bonding.

The last sentence of this proposed section provides that "[w]here two or more principals have interests in different formations or portions of the lease, separate bonds may be posted." First, "principals" is an undefined term. If BLM means lessee or sublessee, it should use the understood terminology in the Proposed Rule. Second, it is unclear what BLM means by "separate bonds may be posted." BLM should clarify if it means separate bonds are a requirement, although if a single well is producing from multiple zones the interests in which are held by different sets of persons, a single bond meeting the requirements for a lease is sufficient to ensure decommissioning of that well.

Additionally, BLM should abandon its proposal to eliminate the option for a nationwide bond authorized under existing § 3104.3(b). BLM asserts in the preamble that nationwide bonds are "administratively inefficient" because they call upon BLM to manage risks nationwide. It further states that the proposed increases in the minimum lease and statewide bond "would allow the agency to ensure improved bonding." These vague justifications that BLM proffers do not outweigh the producing industry's need for a continued nationwide bond to achieve efficiencies and continue providing affordable energy to the U.S. public. The 15-fold increase in the minimum lease bond amount and the 20-fold increase in the minimum statewide bond amount will impose considerable new financial burdens on smaller operators, particularly those with operations across multiple states; a reasonable nationwide bonding option ameliorates those burdens. Also, significant increases and reduced flexibility in bonding requirements may cause smaller operators to prematurely cease operations, thereby increasing risks of bankruptcies and orphan wells. BLM also does not account for the fact that nationwide bonds favorably reduce overall risk by spreading it over a larger geographical area. Further, the elimination of a nationwide bond would create more inefficiencies for BLM by eliminating the ability to cover de minimis acreage positions across multiple states. As a placeholder, the recommended revisions below include the $2 million nationwide bonding level contained in draft bills that resulted in the IRA; as indicated above, however, BLM should reduce that amount as appropriate.

Recommended Revision:

§ 3104.20 Lease bond.

The operator, a lessee, or an owner of operating rights (sublessee) must ~~be covered by~~ provide a bond in its own name as principal or obligor in an amount of not less than $150,000 [or lower amount per comments above] for each lease conditioned upon compliance with all of the terms of the lease. ~~Additional bonding may be posted by a lessee, or owner of operating rights (sublessee), as they are ultimately responsible under § 3106.72.~~ Where two or more ~~principals~~ lease interest holders have interests in different formations or portions of the lease, separate bonds may be posted.

§ 3104.30 Statewide and nationwide bonds.

In lieu of lease bonds, lessees, owners of operating rights (sublessees), or operators may furnish a bond in an amount of not less than $500,000 [or lower amount per comments above] covering all leases and operations in any one State, or in an amount of not less than $2,000,000 [or lower amount per comments above] covering all leases and operations nationwide.

Q. § 3104.40 Surface owner protection bond.

This proposed section conflicts with several state requirements involving split estate and access/surface owner bonding. While BLM must evaluate through NEPA analysis any significant impacts to the surface environment as a result of its approvals or other actions, BLM should not duplicate state requirements for the protection of non-federal surface owners through operator bonding. BLM therefore should add a new subsection (a) acknowledging state requirements where they apply. In addition, BLM should make clear that this section applies only where the surface is not federally owned, consistent with existing 43 C.F.R. § 3171.19(b)(2). BLM also should address the interplay between existing § 3171.19(b)(2), which this Proposed Rule would not modify, and proposed § 3104.40 which may be duplicative or inconsistent. Namely, § 3171.19(b)(2) allows for an "agreement" with the surface owner in lieu of bonding, and such an agreement does not necessarily require payment of "compensatory damages" as proposed in § 3104.40. BLM should also clarify that such bonds are not intended to cover reclamation, but rather only compensation for inadvertent "reasonable and foreseeable damages to crops and tangible improvements" as stated in the Proposed Rule.

Recommended Revision:

(a) This section applies only if:

(i) the relevant state does not have regulations or procedures that provide for surface owner protection bonds; and

(ii) the surface is not federally owned.

R. § 3104.50 Increased amount of bonds.

This section is the same as existing § 3104.5 with only minor changes. However, BLM should use this rulemaking as an opportunity to modify this section to address its longstanding shortcomings. One of the Associations' concerns is that subsection (b) provides that the authorized officer may raise bond amounts if the operator has a "history of previous violations" or otherwise "poses a risk" due to factors such as uncollected royalties due, or decommissioning costs that exceed the present bond amount. First, the reference to "uncollected royalties due" is unclear as to what it includes. It should include only amounts that have been finally determined to be due and owing but that remain unpaid, and not amounts demanded but subject to administrative appeal, payment of which is stayed pending appeal under 30 C.F.R. § 1243.8.

Second, the concept of royalties owed as being a lease obligation is an anachronism due to the treatment since 1996 of federal oil and gas lease royalty obligations under the Federal Oil and Gas Royalty Management Act, as amended by the Royalty Simplification and Fairness Act. Under that statute, royalty obligations are not a general lease obligation, but are proportionate among the lease interest owners. 30 U.S.C. § 1712. Therefore, it no longer is legally proper for BLM to require that any one lease interest owner guarantee payment of the royalty obligations of its co-interest owners in the lease. In addition, any BLM requirement to provide supplemental financial assurance for royalty disputes is duplicative and unnecessary. Under 30 C.F.R. §§ 1243.4 and 1243.8, if you dispute an ONRR royalty payment demand on production from an onshore federal lease and appeal that demand to the ONRR Director or the Interior Board of

Land Appeals, those regulations properly address the need to provide any financial assurance to obtain a stay of the payment demand pending resolution of the appeal.

The reference to "history of violations" also is vague and requires parameters as to the seriousness of the violations, age of the violations, and whether the violations BLM may have asserted are subject to administrative or judicial review. It also is unclear if an operator's violations must have occurred on the same lease or on any federal lease that it operates. It is entirely inappropriate for lease interest owners on a lease to have to provide supplemental financial assurance for violations that occurred on another lease. Alleged noncompliance with BLM operating regulations also should not trigger a need for additional financial assurance if those violations were unrelated to decommissioning or similar significant lease-related financial obligations. For example, a missing seal on an oil tank does not provide a reasoned basis for BLM to demand supplemental financial assurance. To the extent there exist outstanding financial obligations, BLM has adequate enforcement tools to pursue and collect those amounts and should not use supplemental bonding to address that extant alleged noncompliance.

Additionally, for the same reasons explained above for other appeals sections, the regulations should provide that an operator or lease interest owner may seek State Director review of the authorized officer's demand for supplemental financial assurance. IBLA review of the State Director's decision also should be permitted.

Finally, in view of the significant bonding increases under proposed § 3104.50, BLM should afford flexibility in the forms of acceptable financial assurance instruments to satisfy a BLM demand for increased bond amounts. BLM's sister agency BOEM provides for such flexibility in financial assurance for operators on the Outer Continental Shelf. *See, e.g.*, 30 C.F.R. § 556.900(g). Therefore, in addition to traditional bonds, BLM should be able to consider third-party guarantees, abandonment accounts, or other forms of adequate financial security proposed by an operator and acceptable to BLM.

Recommended Revision:

> (b) The authorized officer may require an increase in the amount of any bond whenever it is determined that the operator poses a risk due to a history of failing to perform reclamation on BLM-managed leases or ~~factors, including, but not limited to, a history of previous violations, a notice from the ONRR that there are uncollected royalties due,~~ due to the total cost of plugging existing wells and reclaiming lands exceed~~s~~ing the present bond amount based on the estimates determined by the authorized officer. The increase in bond amount may be to any level specified by the authorized officer, but in no circumstances will it exceed the total of the estimated costs of plugging and reclamation, ~~the amount of uncollected royalties due to the ONRR,~~ plus the amount of money owed to the lessor due to previous violations remaining outstanding. An operator may satisfy a demand for increased bonding by providing another form of security that BLM determines protects the interests of the United States to the same

> extent as a bond. Any person aggrieved by a decision of the authorized officer to increase bond amounts is subject to State Director review, and review by the Interior Board of Land Appeals, in accordance with 43 C.F.R. § 3165.3.

S. § 3104.70 Default.

Subsection (b)(2) adds new disqualification language for those persons who do not cure bonding defaults. Under this new subsection, if you fail to cure your bonding defaults, BLM may prevent you from acquiring new federal lease interests. The Associations object to this additional subsection because it effectuates the equivalent of suspension or debarment even if BLM does not pursue that route under paragraph (b)(3) with its corresponding due process protections. Accordingly, BLM should remove proposed subsection (b)(2).

T. § 3104.90 Bonds held prior to [EFFECTIVE DATE OF THE FINAL RULE].

Because the Proposed Rule's new minimum lease bond requirements are such a significant increase over the minimum bonding levels in existing regulations, BLM also should uniformly allow for a five-year phase-in period to meet all of the different bonding requirements for existing leases, including in proposed §§ 3104.20 and 3104.30, and should modify proposed § 3104.90 accordingly. This modified phase-in would avoid potentially disruptive financial impacts to lessees and to the financial marketplace that lessees and operators rely upon for securing financial assurance for their federal oil and gas lease operations. Moreover, as discussed above, BLM should remove proposed subsection (c) and preserve nationwide bonding.

U. § 3106.42 Transfers of other interests, including royalty interests and production payments.

BLM is updating this section to ensure that transfers of overriding royalty interests, payments out of production, and similar transfers are reported to BLM. BLM should clarify that BLM approval is not required for these transfers.

V. § 3106.60 Bond requirements.

This section requires an assignee of record title or transferee of operating rights to furnish bonding to replace bonding maintained by the assignor or transferor. But proposed § 3104.20 would place the principal bonding obligation for a lease on the operator. BLM should harmonize the two sections consistent with changes recommended to these sections provided above.

W. § 3107.10 Extension by drilling.

BLM is proposing in subsection (c) that when a BLM-approved directional or horizontal well is drilled from an off-lease location, BLM will consider drilling to have commenced on the lease area when drilling begins at the off-lease location. The Associations support this change as reflecting the realities of advanced drilling technologies.

X. § 3107.21 Continuation by production.

Consistent with the change BLM is proposing for § 3107.10(c), BLM should add the following sentence to this section: "When a BLM-approved directional or horizontal well is completed within multiple leased areas, BLM will consider production to have commenced from each of those leased areas." This will confirm that a lease is held by production from the directional or horizontal well.

Y. § 3120.11 Lands available for competitive leasing.

The Proposed Rule amends the introductory sentence of this section from "[a]ll lands available for leasing *shall* be offered for competitive bidding" to "[a]ll lands *eligible and* available for leasing *may* be offered for competitive auction" (emphasis added). The preamble states that addition of the term "eligible" is to better conform to the MLA, 30 U.S.C. § 226(a) and (b), and "better reflect Interior's statutory discretion to identify lands available for oil and gas leasing." But the changed regulatory language would make the decision to lease more flexible for BLM than the statute allows, including making quarterly leasing in each state appear voluntary, by changing "shall" to "may," contrary to recent court decisions in the wake of EO 14008 Section 208. *See State of North Dakota v. DOI*, No, 21-148, ECF No. 98 (D.N.D. Mar. 27, 2023) (slip. op.); *Louisiana v. Biden*, 622 F. Supp. 3d 267, 293-94 (W.D. La. Aug. 18, 2022); *see also W. Energy All. v. Jewell,* No. 16-912*,* 2017 WL 3600740, at *8 (D.N.M. Jan. 13, 2017). The Associations view this proposed provision as another opportunity to inappropriately limit federal leasing. At a minimum, any change to the existing regulation should mirror the precise language of the statute: "Lease sales shall be held for each State where eligible lands are available at least quarterly and more frequently if the Secretary of the Interior determines such sales are necessary."

Z. § 3120.12 Requirements.

BLM is proposing to amend subsection (a) to provide that "[e]ach BLM State Office will hold sales at least quarterly if eligible lands are available for competitive leasing." This is a significant change from existing § 3120.1-1 which provides that "[a]ll lands available for leasing shall be offered for competitive bidding under this subpart . . . . ", with the latter providing less discretion to remove acreage otherwise available for lease. BLM again states in the preamble that "[t]he proposed rule would update paragraph (a) to conform this section with the language of 30 U.S.C. 226(a) and (b)." However, like proposed § 3120.11 above, the proposed language appears to imbue BLM with more discretion than the statute (30 U.S.C. § 226(b)) does. That statute provides: "Lease sales shall be held for each State where eligible lands are available at least quarterly and more frequently if the Secretary of the Interior determines such sales are necessary." BLM's proposed provision here, particularly coupled with BLM's proposed new "preference criteria" in this Proposed Rule and with BLM's separately proposed "conservation and landscape health" rule, appears to reduce acreage for leasing by relying on other, subsequent determinations that lands available under applicable Resource Management Plans should not be "eligible" for leasing due to BLM's later assertion of potential resource "conflicts." Again, at a minimum, any change to the existing regulation should mirror the precise language of the statute quoted above.

AA. § 3120.30—3120.34 Nomination process.

The preamble to the Proposed Rule asks for comment on whether BLM should reinvigorate the "formal" nomination process for parcels to be included in a competitive auction, which to date BLM has largely eschewed in favor of informal expressions of interest ("EOIs"). BLM explains that "[a]side from a few test sales following the enactment of FOOGLRA, the BLM has never employed the formal nomination process." It is unclear how this proposal would function differently than existing EOIs, except to afford BLM another "mechanism" to limit lease areas under its newly expressed criteria. It also is unclear what BLM means when it states that "[t]he proposed rule would update the following sections [§§ 3120.31-.33] for the formal nomination process with the intent to make these nominations *nonbinding* . . . ." Moreover, BLM does not harmonize the BLM Policy Manual on Communitization (at 10), which states that unleased federal lands within communitization agreements "should be offered for competitive leasing as soon as possible." Such federal lands should not be subject to nomination limitations or EOI criteria set forth in the Proposed Rule.

The Proposed Rule further leaves several relevant questions unanswered for this formal nomination process. For example, would BLM go through the same EOI process to track submissions though the system and allow the public to see what the BLM has nominated? How will BLM confirm industry interest in such acreage? Under what criteria would BLM nominate parcels? Will BLM-nominated parcels be counted in the IRA's acreage calculations for onshore solar and wind rights-of-way? On this last point, BLM should not count all such BLM-nominated acreage for IRA purposes as much of that acreage may never be offered or leased or even attract industry interest in a lease sale. Indeed, BLM need only look to the results of recent offerings for onshore solar and Gulf of Mexico offshore wind to observe the disconnect between government and industry perceptions of attractive areas for energy development.

BB. § 3120.33 Parcels receiving nominations.

BLM is amending existing § 3120.3-5 to no longer mandate that BLM include nominated parcels in a competitive lease sale. Instead, BLM would provide that it "may" include such parcels. That is nonsensical. Proposed § 3120.32 provides that nominations are filed in response to a "List of Lands Available for Competitive Nominations." Thus, BLM has already determined that the lands are available to include in a competitive lease sale. BLM should not get another opportunity to exclude parcels on that list from a competitive sale once they are duly nominated.

CC. § 3120.41 Process.

As discussed in the Associations' general comments above, this proposed provision is among the most problematic in the Proposed Rule. At the outset, BLM fails to explain how the process for EOIs is different from the formal nomination process outlined in the Proposed Rule's preceding sections. Considering BLM's acknowledgement that to date it has leased solely based on the EOI process, BLM should fully delineate the respective workings of the two processes, to avoid potentially misapplying the formal process as an opportunity to constrain access to federal oil and gas while claiming credit toward IRA offered acreage targets.

More critically, subsection (f) introduces "preference criteria" for BLM to utilize in selecting lands to offer in onshore lease sales in response to EOIs. Again, the subjectivity and uncertainty of these criteria contradict BLM's professed rejection of "subjective" criteria and embrace of "certainty." 88 Fed. Reg. at 47,574, 47,565. Also, these preference criteria are ill-defined or undefined. For example, "important fish and wildlife habitats or connectivity areas" is a very broad concept. It potentially captures far more than an Area of Critical Environmental Concern ("ACEC"), which is already subject to existing defined criteria, procedures, reporting, and mitigation.[22] Existing laws such as FLPMA, the Clean Water Act, and the Endangered Species Act already balance multiple uses and protect water bodies and species on BLM lands, and refusing to lease in an area with "important" habitat is unclear and unnecessary. To the extent that the "important" area is already covered by another existing law, the preference criteria would be duplicative. And to the extent the preference criteria are used to exclude additional areas from leasing, the Proposed Rule fails to follow the appropriate procedures for area designation or acreage withdrawal, including a public comment process.[23] The same is true for "historic properties" under the National Historic Preservation Act and laws protecting specific cultural lands. The MLA clearly does not vest BLM with jurisdiction to achieve the same ends as these other statutes.

What is more, BLM purports to set forth only "minimum" criteria in this subsection, and states that it "would consider additional criteria and factors." 88 Fed. Reg. at 47,590. BLM then invites inclusion of additional factors such as "environmental justice concerns" and "greenhouse gas emissions," and does so without appropriate parameters for their consideration. *Id.* at 47,566, 47,590. The Associations are concerned that BLM could wield such additional criteria to simply reduce federal oil and gas leasing—whether or not those criteria are expressly adopted in a final rule. This proposed subsection (f) could be used to functionally freeze oil and gas activities to already existing areas and eliminate new *exploratory* oil and gas development on federal lands. *E.g., id.* at 47,591 ("The BLM would implement this EOI preference process to conserve certain public lands . . . ."); *id.* ("For example, offering leases where current infrastructure exists should reduce the overall footprint of energy development and limit wildlife impacts and habitat fragmentation."); § 3120.41(f)(1) (BLM will consider "[p]roximity to oil and gas development existing at the time of the BLM's evaluation, giving preference to lands upon which a prudent operator would seek to expand existing operations").

The Associations and their member companies share the same commitment as BLM to ensuring that environmental justice concerns are addressed. We support the core principles that uphold environmental justice policy and practice: fair treatment and meaningful engagement, and the industry strives to ensure safe and responsible operations, respecting the communities and the environment where the industry operates. The industry is deeply committed to working with local communities and policymakers to promote these principles across the energy sector. However, BLM should not develop additional criteria in this rulemaking, but instead work with the ongoing CEQ efforts, including on environmental justice, to ensure an aligned and streamlined regulatory process. Specifically, on July 31, 2023, CEQ proposed Phase 2 revisions to its regulations implementing the NEPA, 40 C.F.R. parts 1500-1508. Environmental justice has long been a part of NEPA analysis; however, for the first time, the Proposed Rule would

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[22] *See* 43 U.S.C. § 1712(c)(3); 43 C.F.R. § 1610.7-2; BLM IM 2023-013.
[23] *See id.*; 43 U.S.C. § 1714.

codify a definition of "environmental justice" for NEPA purposes. BLM's proposal to prematurely implement additional criteria could lead to inconsistencies across regulatory programs, resulting in uncertainty and delays. Also, adding criteria that could potentially duplicate NEPA and efforts by other agencies creates redundancy and administrative complexity.

Furthermore, at the leasing stage, neither BLM nor an operator can forecast with certainty what specific mitigation efforts the operator may undertake to address environmental or environmental justice considerations. BLM should not prejudge how operations on the tract will be conducted in determining whether to exclude the lands entirely from leasing. For example, some operators are voluntarily undertaking extensive programs aiming to achieve or approach carbon net zero operations in basins.

Overall, BLM fails to explain why the preference criteria are needed in the first place. The Proposed Rule suggests that the preference criteria are separate from and precede NEPA review. *Id.* ("The preference criteria generally would be applied before the NEPA analysis is completed."). It is unclear what this means, or how this would avoid improper predetermination of the NEPA process that is specifically intended to analyze such criteria. Furthermore, the preference criteria are likely unnecessary given the greatly reduced surface impacts associated with today's well drilling and completion technology. Lessees may now elect where practicable (as opposed to being compelled by BLM under the Proposed Rule) to horizontally drill well laterals from many miles away while avoiding impacts to any sensitive resources located on a BLM lease. Lessees also operate pursuant to well-developed state programs, such as the Wyoming Executive Order on Greater Sage Grouse, that demonstrate oil and gas development's successful coexistence with wildlife conservation.

Accordingly, BLM should remove subsection (f) from this section of the Proposed Rule. BLM also should not adopt additional potential criteria such as those contemplated in its preamble. Doing so, particularly when coupled with other surface use restrictions in the Proposed Rule, would only detract from the predictability and functionality of BLM federal oil and gas leasing.

DD. § 3120.42 Agency inventory of leasing.

Section 50265(b)(1) of the IRA provides that during the 10-year period following enactment, BLM may not issue a right-of-way for wind or solar energy development on public domain or acquired lands unless BLM has held an onshore oil and gas lease sale in the 120 days preceding the right-of-way issuance, and during the 1-year period preceding the right-of-way issuance BLM has held oil and gas lease sales the total acres of which exceed the lesser of 2,000,000 acres or 50 percent of the acreage for which expressions of interest were submitted for lease sales during that 1-year period. BLM issued IM 2023-006 to establish a process for counting the acreage offered to implement this statutory prerequisite.

Proposed § 3120.42 provides that BLM will periodically calculate the "acreage for which expressions of interest have been submitted" and total "acres offered for lease," both of which are newly defined terms in proposed § 3000.5. Yet proposed § 3120.42 provides no calculation method. This problem is compounded by proposed § 3000.5's exclusion of expressions of interest acreage that previously was "proposed for leasing" in "any pending sale" or in any "other expression of interest pending BLM disposition." For the record, BLM should not rely upon IM 2023-006 or other aspects of the Proposed Rule that are inconsistent with the requirements of the IRA by improperly inflating acreage totals nominated or offered for federal onshore oil and gas leasing, or by improperly decreasing the number of acres included in the determination of acreage for which EOIs were submitted. Indeed, BLM has not explained why the agency finds it necessary to itself nominate lands if prospective operators have not expressed interest in those lands and they thus are unlikely to be successfully bid or produced.

EE. § 3120.63 Award of Lease.

Under the last sentence of subsection (e) of this proposed section, "[i]f the BLM cannot issue the lease within 60 days, the BLM may reject the offer." BLM should not adopt this proposed sentence, which sets up possibly routine rejection by BLM of winning lease offers after a competitive sale is held. The corresponding preamble text merely points to delays from the existence of protests and legal challenges to lease sales, and BLM "policy" to allow the high bidder to await resolution or decline the lease. It nowhere justifies BLM unilaterally rejecting a lease offer. Indeed, the last sentence of subsection (e) is incompatible with the rest of this proposed section and the existing regulation foreclosing a high bidder from withdrawing its bid. Nor should BLM's preamble anticipate that "[t]hese protests and challenges may require the BLM to complete a corrective environmental analysis to reach resolution." Rather, BLM should stand behind its NEPA and other analyses.

III. PART 3150

A. § 3151.30 Collection and submission of data.

The Associations have concerns with this new proposed section of the regulations requiring submission to BLM, and possibly public release, of results of geophysical exploration activities nationwide. BLM provides no basis for this requirement or discussion as to why BLM needs this information, how it will be used, or with whom it will be shared. Operators have spent significant funds to conduct these explorative surveys, and the resulting data is highly confidential business information ("CBI"). At a minimum, if BLM requires the submittal of this information, BLM should treat it as presumptively CBI and accordingly not disclose it to the public or competitors under 43 C.F.R. part 2.

IV. PART 3160

A. § 3162.3-4 Well abandonment.

The Associations oppose subsection (c)'s imposition of a maximum four-year period "except in extraordinary circumstances" to permanently abandon wells that the Proposed Rule defines as temporarily abandoned. In some fields, an operator may not know within four years whether it will need that well, including for secondary recovery operations, water injections, or other purposes. The Associations are concerned that BLM may not consider such circumstances as "extraordinary" to extend the proposed four-year maximum period. It would be wasteful and more environmentally impactful to inflexibly require an operator to permanently abandon a well and later have to drill a replacement well. Rather, the maximum period to permanently abandon temporarily abandoned wells should be the same as for shut-in wells in subsection (d), allowing for additional one-year periods where warranted.

BLM also should delete proposed paragraph (d)(1) in this section. Shut-in wells should not require separate notices to the BLM within 90 days of shutting in a well. Wells are required to be reported on the ONRR Form-4054 ("OGOR") beginning with the last month of drilling and continuing until the well is abandoned. Thus, shut-in wells already are reported (Well Status codes 12 (OSI) and 13 (GSI)). This reporting requirement should suffice, and BLM can track these wells through monthly OGOR reports. If it is BLM's intention to track wells that are shut in for extended periods, i.e., up to the 3 years noted in paragraph (d)(2), then the rule should make it clear that it does not apply to wells that are shut in only for short periods of time. In particular, this circumstance would include wells that are shut in periodically but have actual production each month (in which instance the OGOR would show the wells as producing wells).

V. PART 3170

A. § 3171.14 Valid Period of Approved APD.

The Associations support BLM's goal to reduce administrative burdens associated with APD extension requests. However, there is often good cause for such extensions, and as the Proposed Rule's preamble points out, nearly all wells were spud within four years of approved APDs. Accordingly, the most efficient and equitable method to achieve BLM's goal is to establish a uniform four-year term for an APD, rather than two or three years as BLM proposed. A four-year APD term also more closely correlates with NEPA review accompanying an APD approval, given that NEPA review typically remains valid for at least a five-year period (absent significantly changed circumstances). BLM also should clarify that any new time limitation would apply only prospectively to APDs issued after the effective of a final rule. Moreover, BLM needs to provide a procedure for an operator to obtain an approved sundry notice that its APD remains valid in circumstances covered by proposed § 3171.14(b).

VI. MISCELLANEOUS

Beyond the above comments, the Associations offer a few final overarching comments regarding the Proposed Rule's preamble and discussion of "procedural matters." First, despite its preamble's broad statement, it is not for BLM to determine that every provision in the proposed rule is "severable." 88 Fed. Reg. at 47,566. Rather, that determination is for a court in any legal challenge to the Proposed Rule in part or in whole. In any event, BLM's revision of its Proposed Rule as recommended in these comments should help obviate this issue.

Second, BLM cannot rely on the "public welfare" clause in 30 U.S.C. § 187 (MLA) to support widespread curtailment of leasing. *Id.* at 47,565, 47,573. This provision speaks to terms to be included in leases, and the specific clause (following the final semicolon) addresses economic terms for reasonable wages and prices for federal mineral production. Moreover, the Proposed Rule fails to link its proposals to any aspect or measure of the public welfare. As discussed above, existing regulations are already sufficiently protective of public resources. Furthermore, the Proposed Rule nowhere accounts for the fact that sharp curtailment of federal oil and gas activities would injure the public welfare via lost jobs and diminished economic support for reliant or disadvantaged communities and states.

Finally, BLM makes a counterfactual assumption that the Proposed Rule will have no substantial effects on energy supply. *Id.* at 47,613. That appears to be impossible if BLM is actually significantly curtailing future federal onshore oil and gas leasing via this Proposed Rule, as BLM elsewhere indicates should occur. *Id.* at 47,591, 47,613-14. Moreover, BLM offers no evidence for its presumption that lessees can freely rededicate resources from federal to non-federal lands. BLM's conclusion also ignores significant cumulative cost impacts on oil and natural gas operators stemming from BLM's full suite of proposed rulemakings, such as the proposed Waste Prevention Rule (cited *supra*) and forthcoming Site Security and Measurement rules.

* * *

Thank you for the opportunity to provide these comments. The Associations and their members remain committed to working with BLM on the subject matter of the Proposed Rule. Please do not hesitate to contact us if you have any questions.

Sincerely,

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Economic Benefits of Onshore Federal Oil and Natural Gas Leasing from FY 2013 – 2022

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Executive Summary

The development of oil and natural gas resources on federal lands yields significant economic benefits. The oil and natural gas industry generates direct benefits via production on federal lands and revenue sharing in which approximately 50 percent of bonuses, rents, and royalties are shared with the state where they occur. These benefits bolster local government services like education and healthcare. Additionally, the oil and natural gas industry also generates indirect economic benefits that arise from the industry's purchases of goods and services, along with induced benefits that result from direct and indirect labor spending the income they earn from the industry.

To analyze these impacts, we utilize the IMPLAN model. This model relies on publicly available "input-output" tables from the US Bureau of Economic Analysis which establishes connections between industries' purchases and their corresponding output. In this study we examine the benefits of onshore federal leasing generated between FY 2013 and FY 2022 with a specific focus on development in New Mexico, Wyoming, North Dakota, Colorado, and Utah. We find that in FY 2022, onshore federal oil and natural gas development supported nearly 250 thousand jobs, generated $19.4 billion in labor income, and contributed $36.7 billion to GDP. Between FY 2013 and FY 2022, we estimate that onshore federal oil and natural gas leasing supported an average of 190 thousand jobs, generated $13.4 billion in labor income, and contributed $24.2 billion to GDP each year.

Economic Benefits of Federal Leasing, FY 2013 – FY 2022

Completion Cost Estimates

Wells Spud

Based on Bureau of Land Management (BLM) data, five states represented 95.5 percent of the 2,063 well bores started on federal lands in FY 2022—New Mexico (59.3 percent), Wyoming (14.5 percent), North Dakota (8.0 percent), Colorado (8.0 percent), and Utah (5.6 percent). Between FY 2013 and FY 2022, 92.2 percent of wells spud were located in the five aforementioned states—see Figure 1. Given that New Mexico, Wyoming, North Dakota, Colorado, and Utah account for the majority of wells spud as well as oil and natural gas production on federal lands, we focus on these five states and combine all other states.

Figure 1. Wells Spud by State and Period

State	Wells Spud, FY 2022	Percent	Well Spud, FY 2013 - FY 2022	Percent
New Mexico	1,223	59.3	7,037	39.2
Wyoming	300	14.5	4,419	24.6
North Dakota	166	8.0	1,771	9.9
Colorado	165	8.0	1,900	10.6
Utah	116	5.6	1,411	7.9
Other	93	4.5	1,408	7.8
Total	2,063	100	17,946	100

Source: Bureau of Land Management.

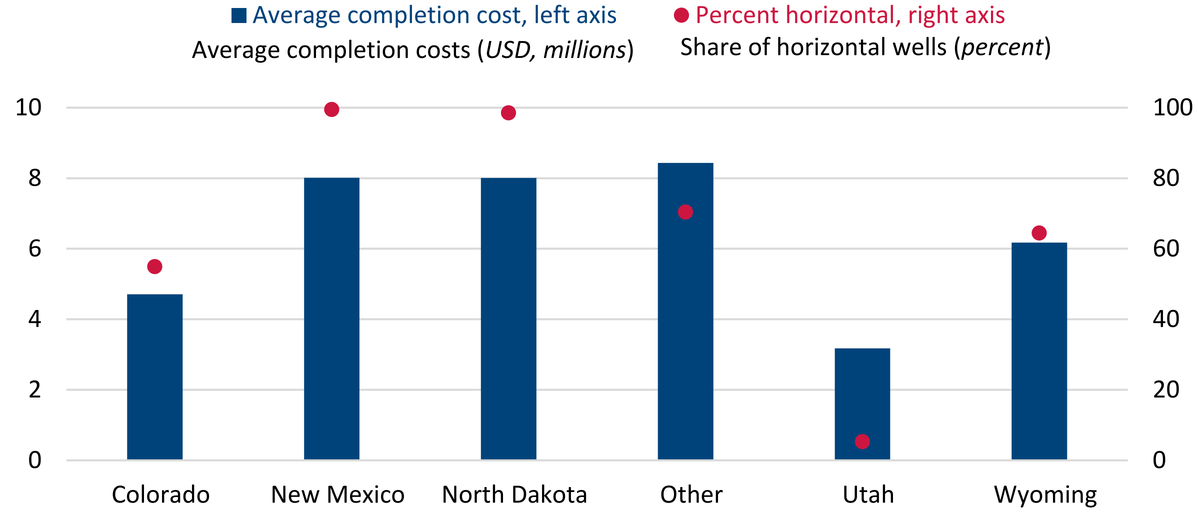
Note: This figure does not include "Indian leases."

Average Completion Costs per Well Bore

Rystad Energy collects and estimates completion costs for over 500 thousand wells and separates these costs into ten categories—drilling services, facilities, fuel and power, oil country tubular goods, other completion costs, other drilling costs, proppant, rig, stimulation, and water. We restrict the wells in our sample to those drilled between FY 2013 and FY 2022, that had a BLM lease and were not on Indian land. These restrictions reduce the number of wells spud between FY 2013 and FY 2022 to 16,200, roughly matching BLM's well spud estimates. As in the BLM data the top five federal oil and natural gas producing states, in Rystad's data, represent roughly 95.0 percent of wells spud on federal land between FY 2013 and FY 2022.

We generate average completion costs by state and fiscal year, using Rystad's cost data based on the well's spud date. In FY 2022, the average cost of a completed well on federal lands was $7.0 million. State well completion costs ranged from $3.2 (Utah) to $8.0 (North Dakota) million—see Figure 2. These cost differences are partly explained by well direction. For example, whereas 94.7 percent of wells spud on federal lands in Utah were either directional or vertical, in North Dakota 98.5 percent of wells spud on federal lands were horizontal. Relative to directional or vertical wells, horizontal wells have higher completion costs. In FY 2022, 82.6 percent of wells spud on federal lands were horizontal. Compared to FY 2013, the percentage of wells spud that are horizontal (34.6 percent) has increased 48 percentage points. While horizontal wells, typically, have higher completion costs than vertical wells, they are generally more productive and reduce oil and natural gas well's surface footprint.

Figure 2. Average Completion Costs and Well Direction by State, FY 2022

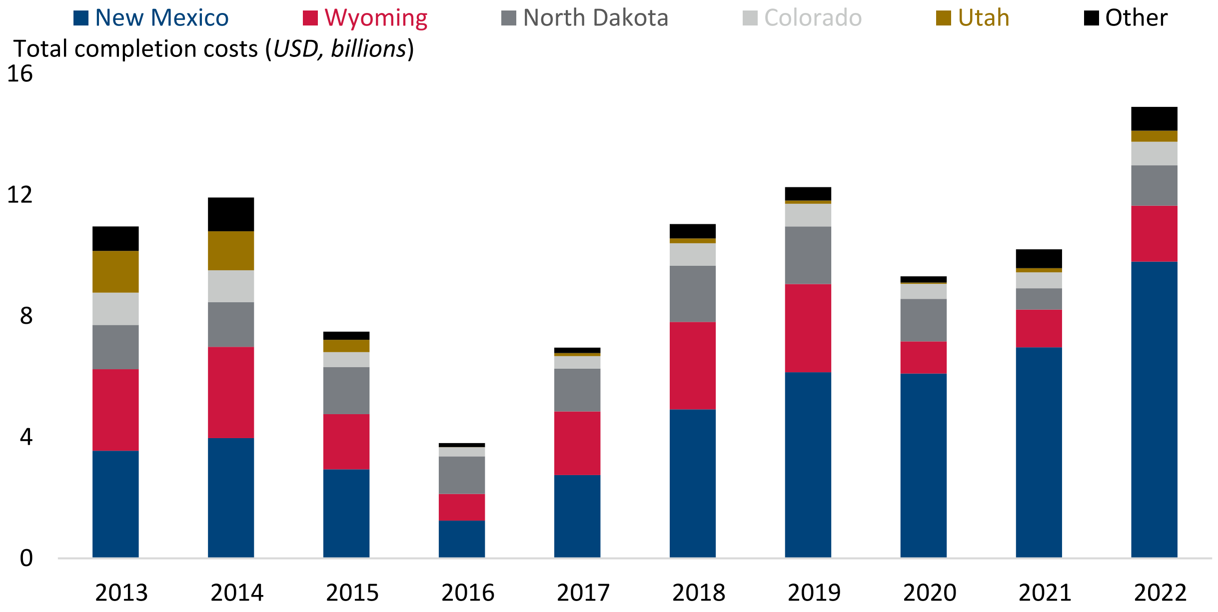


Sources: Rystad Energy; API calculations.

Total Federal Onshore Completion Costs

Having determined average completion costs by state, we estimate total completion costs by multiplying Rystad's well completion cost data by BLM's well spud data. This procedure generates total completion costs by state and fiscal year—see Figure 3. Between FY 2013 and FY 2022, firms spent $98.8 billion on onshore federal well completions or about $9.9 billion per year. Completion costs in New Mexico (49 percent), Wyoming (21 percent), and North Dakota (15 percent) represented 84 percent of total onshore federal well completion expenditures. In FY 2020, completion costs dropped 24 percent year over year but have rebounded thereafter. In FY 2022, total completion costs were roughly $15 billion and were up 46 percent year over year.

Figure 3. Total Well Completion Costs by State, FY 2013 - 2022



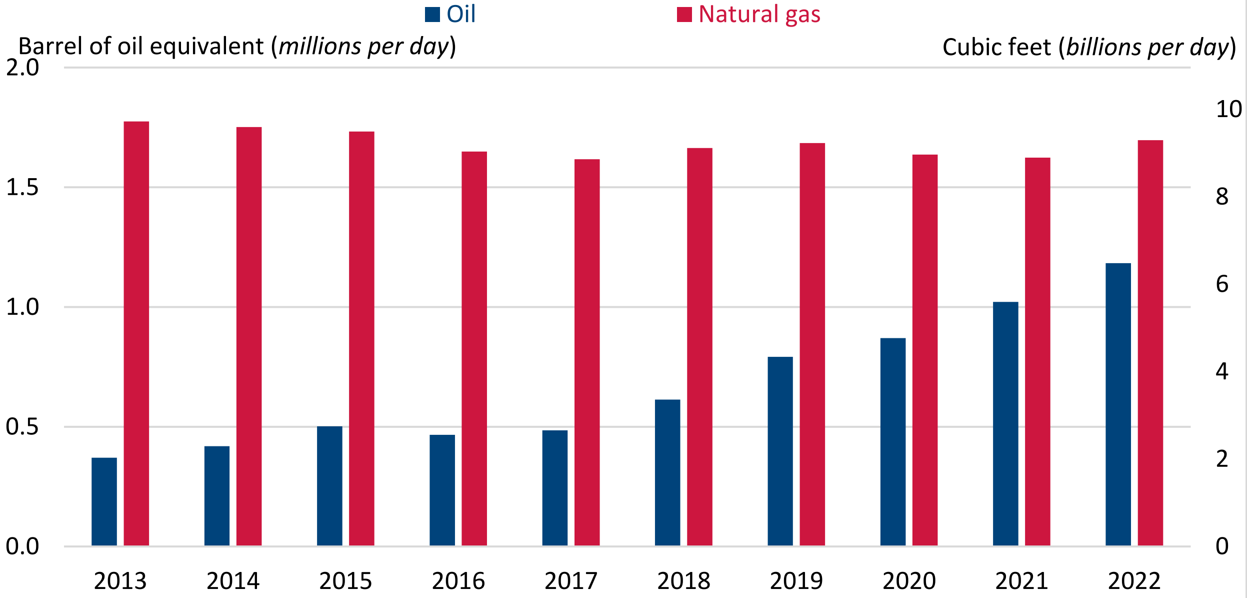
Sources: Rystad Energy; Bureau of Land Management; API calculations.

Production Estimates

Federal Production Estimates

We estimate production expenditures by state and fiscal year using Rystad's per barrel of oil equivalent (BOE) cost estimates and the Office of Natural Resources Revenue's (ONNR) production data. First, we use ONNR's production data to determine onshore federal natural gas and oil production[1] in BOE[2] terms. Between FY 2013 and FY 2022, federal lands produced roughly 1.7 million BOE of natural gas per day and about 672 thousand barrels per day of oil. Over the ten year period, federal lands produced 8.6 billion BOEs of natural gas (6.1 billion) and oil (2.5 billion)—Figure 4. While natural gas production has declined by 4.4 percent between FY 2013 and FY 2022, oil production has tripled. Over the same period, ninety-five percent of production occurred in Wyoming (36 percent), New Mexico (33 percent), Colorado (16 percent), Utah (6 percent), and North Dakota (5 percent).

Figure 4. Federal Onshore Oil and Natural Gas Production, FY 2013 - FY 2022



Sources: Office of Natural Resources Revenue; API calculations.
Notes: Production estimates do not land classes designated as "mixed exploratory" or "Native American."

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[1] We only include production on the land classes designated "federal" which excludes "mixed exploratory" and "Native American" land classes.

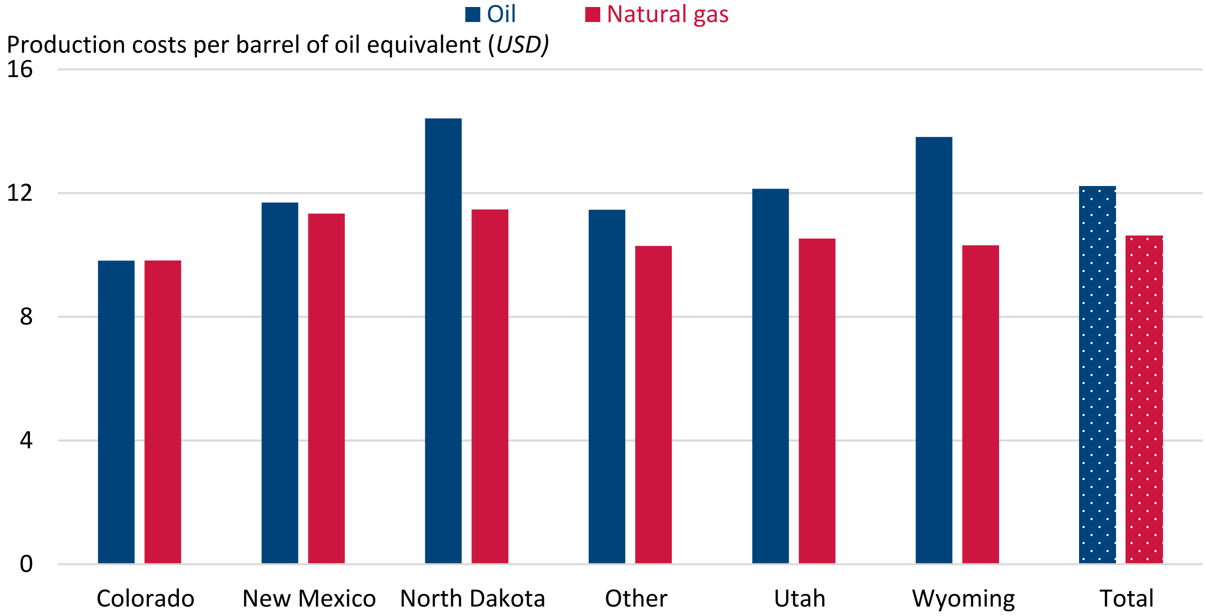
[2] We convert natural gas thousand cubic feet (MCF) to barrel of oil equivalents using a conversion factor of 5.478.

Production Cost Estimates Per Barrel of Oil Equivalent

Rystad estimates production cost per BOE by product type—i.e., oil and natural gas—and includes costs associated with taxes; selling, general and administrative expenses; transportation; production; and abandonment. Rystad presents their production cost estimates by state and calendar year. Their data does not allow us to derive production cost estimates, specifically, for federal lands as Rystad's per barrel production estimates include all onshore production. However, we believe that the composition of private and federal wells is likely similar and that their production costs do not vary substantially excluding federal royalties which we discuss in the following section.

We find that the average unweighted production cost associated with a barrel of oil is roughly $12 and that the average unweighted production cost associated with a BOE of natural gas is about $11. However, we find that average production costs vary by state—see Figure 5. For example, in California the average production cost per barrel of oil was $22, over the period, which is about 1.6 times higher than the US average unweighted production cost per barrel of oil. Similarly, in California the average natural gas production cost per barrel of oil equivalent was $16, over the period, which is about 1.4 times higher than the national unweighted average production cost per barrel of oil equivalent.

Figure 5. Average Production Costs per Barrel of Oil Equivalent, 2013 - 2022

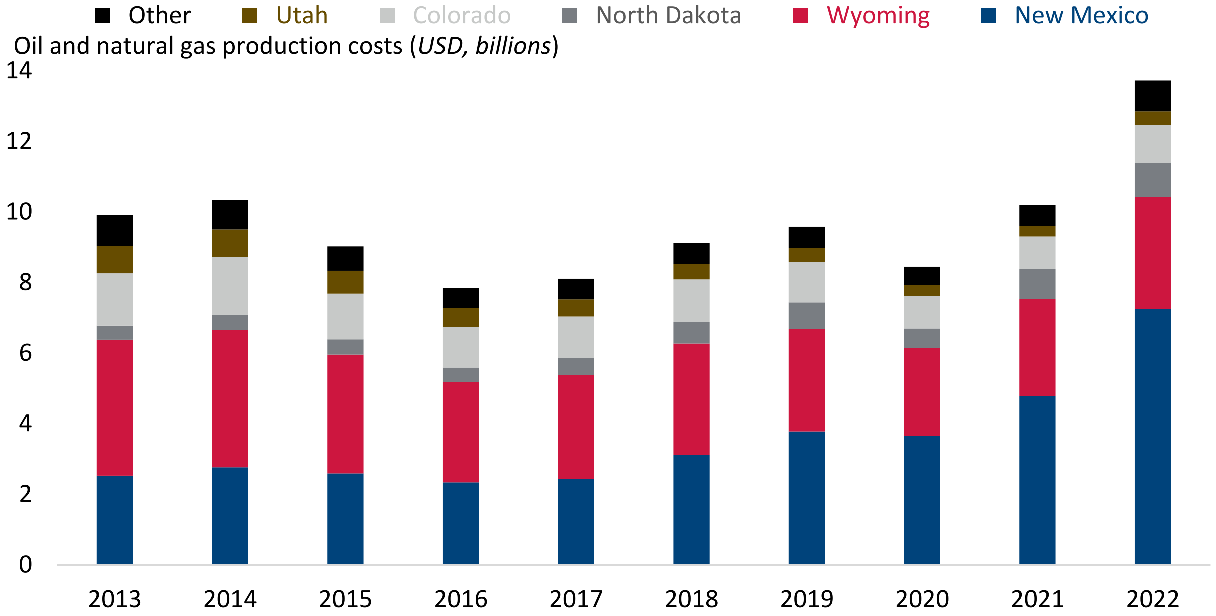


Sources: Rystad Energy; API calculations.

Total Production Costs

We generate total production costs by state and fiscal year, using Rystad's per barrel of oil equivalent production cost data in combination with ONNR's production data.[3] Multiplying Rystad's, respective, per barrel production costs by ONNR's, corresponding, production data generates our total production cost estimates—see Figure 6. We estimate that, between FY 2013 and FY 2022, firms spent $92 billion on production costs, roughly $9.2 billion each year. Production costs were primarily located in Wyoming (35 percent), New Mexico (33 percent), and Colorado (13 percent) representing 82 percent of total expenditures.

Figure 6. Total Federal Land Production Expenditures by State, FY 2013 - 2022



Sources: Rystad Energy; Office of Natural Resources Revenue; API calculations.

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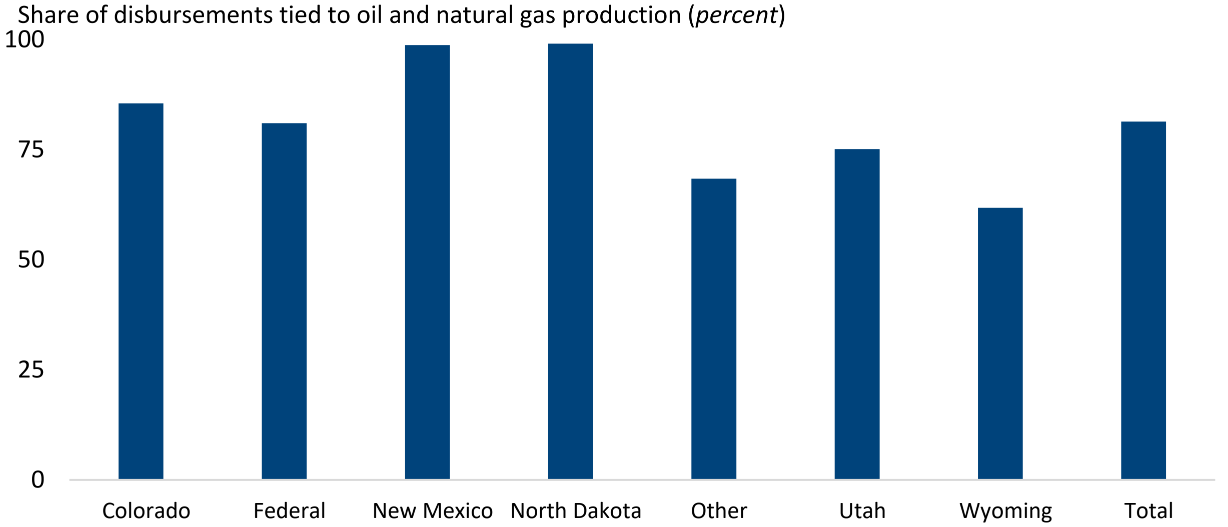
[3] Because Rystad presents their data in calendar years and the rest of our study is in fiscal years, we match the nearest calendar year in Rystad's production cost data to the nearest fiscal year in ONNR's production data.

Oil and Natural Gas Disbursements

We estimate disbursements generated by federal onshore oil and natural gas production using ONNR disbursement data.[4] ONNR only offers disbursement data by commodity as of FY 2017. Prior to FY 2017, ONNR did not distinguish disbursements by commodity. We estimate disbursements by commodity between FY 2013 and FY 2016 as follows. First, we use ONNR's FY 2017 – FY 2022 data excluding disbursements tied to offshore production and fund types designated as Native American Tribes & Allottees. Second, we group disbursements into two categories 1) oil and natural gas[5] and 2) other such as wind, sulfur, etc. Finally, we determine the percent of disbursements that were tied to oil and natural gas production by recipient and fiscal year.[6] Between FY 2017 and FY 2022, the percentage of disbursements that were tied to oil and gas production varied by recipient—see Figure 7. For example, in New Mexico and North Dakota almost all disbursements were tied to onshore oil and natural gas production, while in "other" states only 66 percent of disbursements were tied to onshore oil and natural gas production.

Figure 7. Average Share of Onshore Disbursements Tied to Oil and Natural Gas Production by Recipient, FY 2017 - FY 2022



Sources: Office of Natural Resources Revenue; API calculations.

Notes: In New Mexico and North Dakota, the proportion of disbursements allocated to oil and gas, ocassionally, exceeded a 100 percent. We capped disbursements at 100 percent.

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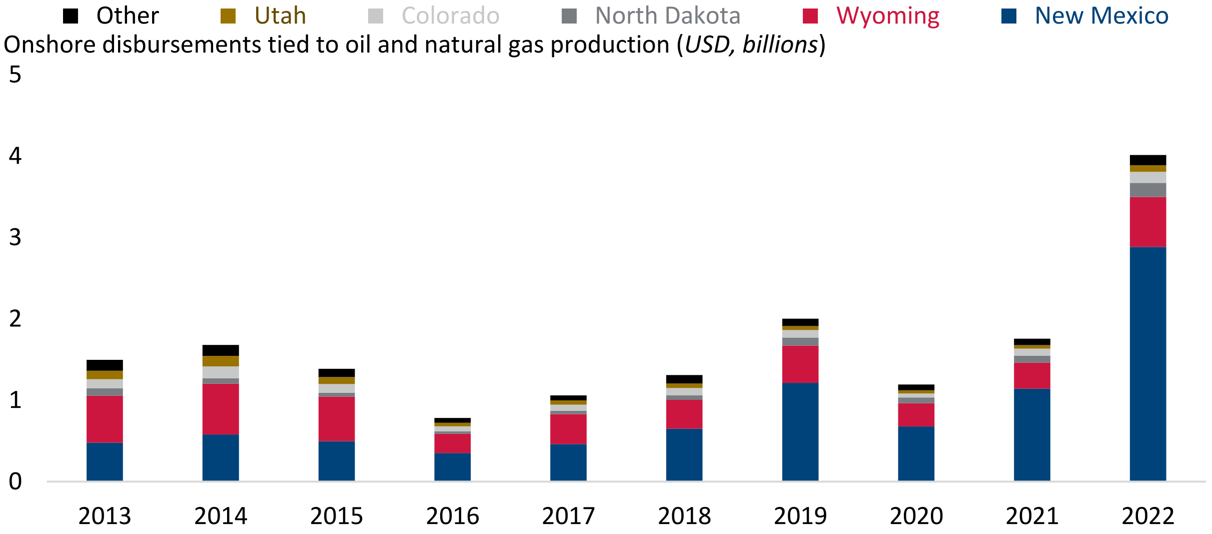
[4] We rely on disbursement data instead of revenue data because it allows us to identify the recipient of the disbursement which is required for our IMPLAN calculations.

[5] Oil and natural gas include commodities identified as oil & gas (pre-production), oil, and gas.

[6] In New Mexico and North Dakota, the proportion of disbursements allocated to oil and gas exceeded a 100 percent. We capped disbursements at a 100 percent.

We then apply our ratios of onshore disbursements between FY 2017 and FY 2022 by recipient to ONNR's FY 2013 and FY 2016 disbursement data[7], to approximate the share of disbursements that were likely tied to oil and natural gas production on federal lands—see Figure 8. We find that, between FY 2013 and FY 2022, recipients received a total of $35 billion in oil and natural gas disbursements equal to roughly $3.6 billion a year. Fifty-three percent ($19 billion) of disbursements went to the federal government or programs, while state and local governments received the remaining 47 percent. Of the 47 percent of disbursements that went to state and local governments, New Mexico and Wyoming received 80 percent (roughly $13 billion).

Figure 8. Onshore Disbursements Tied to Oil and Natural Gas Production by Recipient, FY 2013 - FY 2022



Sources: Office of Natural Resources Revenue; API calculations.

Notes: We estimate FY 2012 to FY 2016 disbursements based on the share of oil and natural gas disbursements between FY 2017 - 2021. This figure does not include disbursements to the federal government or federal programs.

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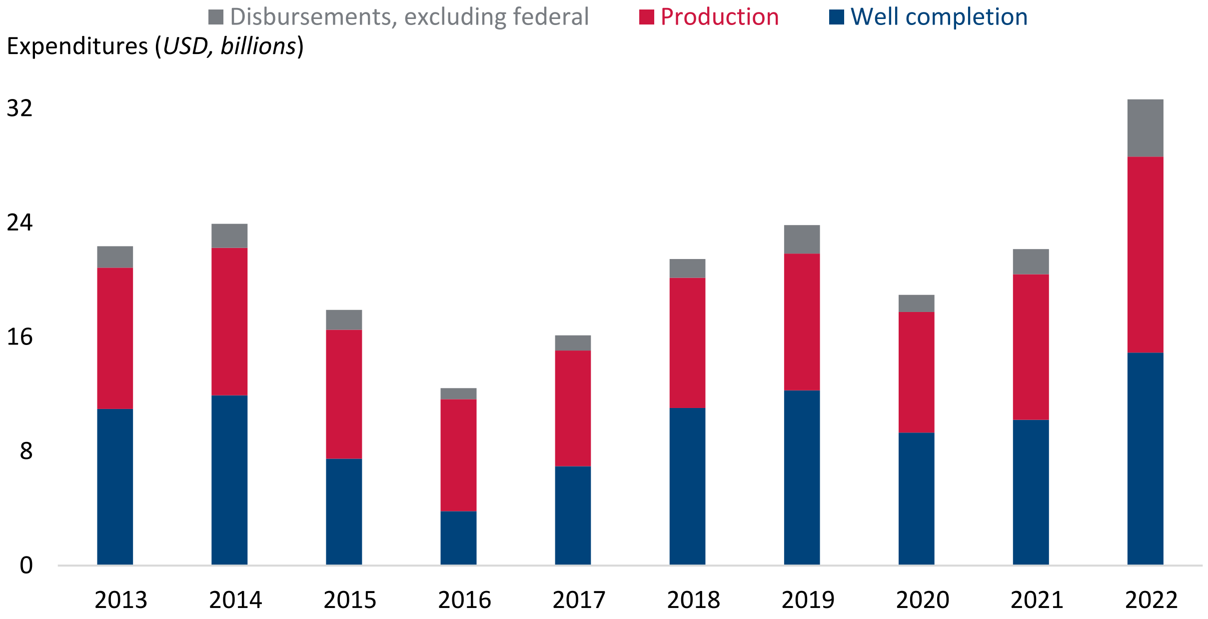
[7] We remove disbursements that are not identified as onshore or that are tied to "Native American tribes and individuals" fund types. These changes align ONNR's FY 2012 – FY 2016 data, with ONNR's FY 2017 – FY 2022 data.

Total Expenditures and Disbursements

Between FY 2013 and FY 2022, firms spent roughly $212 billion on federal onshore oil and natural gas production—disbursements, excluding federal ($16.7 billion), production ($96.2 billion), and well completion ($98.8 billion). Over the period, average expenditures were roughly $21.2 billion per year. Total expenditures were clustered regionally, New Mexico (44 percent), Wyoming (27 percent), North Dakota (10 percent), and Utah (10 percent). To determine these expenditures impact on employment and economic growth we use IMPLAN and allocate total expenditures to impact categories that correspond to the specific expenditures and state where they occurred.[8] We do not include oil and natural gas disbursements received by the federal government in our economic modelling—see Figure 9.

Figure 9. Total Expenditures by Category, FY 2013 - FY 2021



Sources: Bureau of Land Management; Rystad Energy; Office of Natural Resources Revenue; API calculations.

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[8] The IMPLAN categories we use for well completion costs are 29 (sand and gravel mining), 35 (drilling oil and gas wells), 36 (support activities for oil and gas operations), 49 (water, sewage and other systems), 216 (Iron, steel pipe and tube manufacturing from purchased steel), 264 (oil and gas field machinery and equipment manufacturing), and 399 (wholesale, petroleum and petroleum products). We group all production expenditures into the IMPLAN category 20 (oil and natural gas extraction). We distribute oil and natural gas disbursements between four IMPLAN categories—539 (state education), 540 (health services), 541 (other state) and 542 (local education)—based on IMPLAN's state level estimates of payroll expenditures. In all cases, we allocate the expenditures to the states that they accrue expect for OCTG costs which we assign to "other" states as little OCTG expenditures occur in the five states where the lion share of oil and natural gas production occurs.

Employment and Economic Benefits

Using the IMPLAN model we find that in FY 2022, onshore federal oil and natural gas development supported nearly 250 thousand jobs, generated $19.4 billion in labor income, and contributed $36.7 billion to GDP—see Figure 10. Notably, drilling and development contributed the most to total jobs and labor income, while extraction resulted in the highest total GDP. While direct benefits primarily accrue to five states with the most federal oil and natural gas development the indirect and induced impacts reach the entire US economy—see Figure 11. The "other" category experiences the highest indirect and induced economic effects, reflecting the widespread influence of supply chain purchases and general induced spending. New Mexico currently leads with the largest economic impact, accounting for approximately 40 percent of the total US impact.

Figure 10. Economic Benefits of Federal Oil & Natural Gas Leasing, Fiscal Year 2022

Source	Employment (*thousands*)			Labor Income (*billions, USD*)			GDP Contributions		
	Direct	Indirect & induced	Total	Direct	Indirect & induced	Total	Direct	Indirect & induced	Total
Extraction	12.1	58.8	71.0	1.5	4.8	6.3	8.6	7.4	16.0
Drilling & Development	35.6	76.9	112.6	3.6	5.2	8.8	6.2	9.0	15.1
Revenue Sharing	48.1	15.8	63.9	3.5	0.8	4.3	4.0	1.5	5.6
Total	95.8	151.6	247.4	8.6	10.8	19.4	18.8	17.9	36.7

Sources: Bureau of Land Management; Rystad Energy; IMPLAN; API calculations.
Notes: US impacts only.

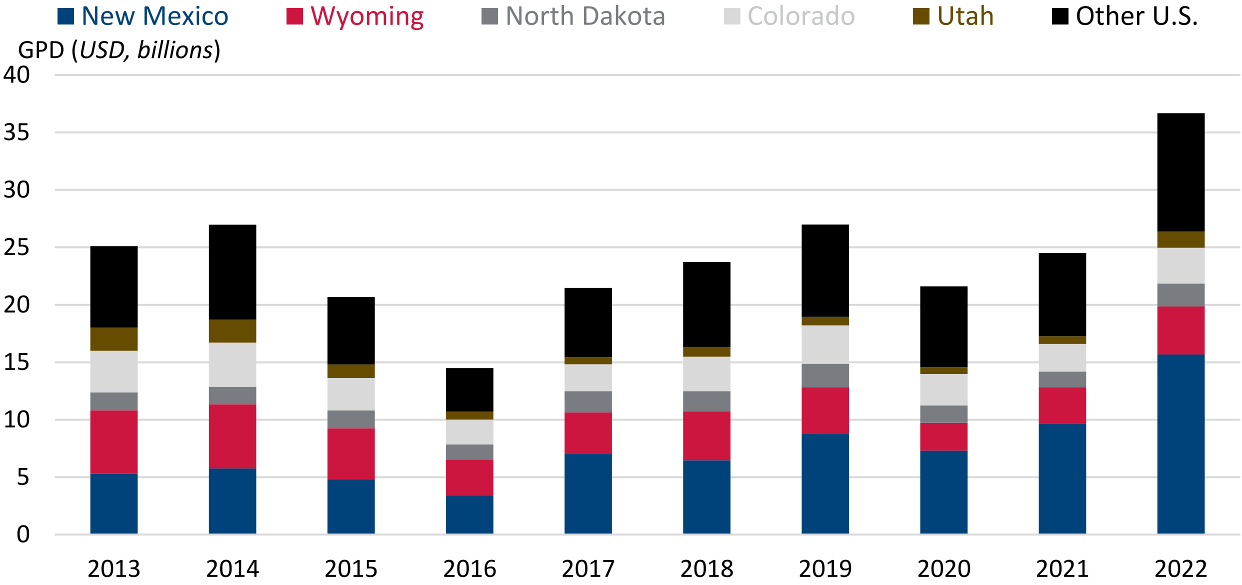
Figure 11. Economic Benefits of Federal Oil & Natural Gas Leasing by State, FY 2022

Source	Employment (*thousands*)			Labor Income (*billions, USD*)			GDP Contributions		
	Direct	Indirect & induced	Total	Direct	Indirect & induced	Total	Direct	Indirect & induced	Total
Colorado	4.4	16.6	21.0	0.9	1.4	2.3	1.1	2.1	3.1
New Mexico	64.0	41.3	105.3	5.2	2.2	7.4	11.5	4.2	15.7
North Dakota	5.5	4.5	10.0	0.5	0.3	0.8	1.5	0.5	2.0
Utah	3.0	8.1	11.2	0.2	0.6	0.8	0.6	0.9	1.4
Wyoming	15.1	9.3	24.4	1.3	0.5	1.8	3.2	0.9	4.2
Other	3.8	71.7	75.5	0.5	5.8	6.3	1.0	9.4	10.3
Total	95.8	151.6	247.4	8.6	10.8	19.4	18.8	17.9	36.7

Sources: Bureau of Land Management; Rystad Energy; IMPLAN; API calculations.
Notes: US impacts only.

Examining ten-year trends of employment labor income, and GDP—see Figure 12 and 13—FY 2022 stands out as the year with the most substantial economic impact, largely driven by the growing impacts of the New Mexico portion of the Permian Basin. Colorado, Utah, and Wyoming have generally shown declining economic impacts from federal Leasing over the last decade, with a minor post-COVID-19 economic rebound in 2022. Conversely, North Dakota's economic impacts have exhibited variations over the years, without showing a definitive upward or downward trend. We find that between FY 2013 and FY 2022, onshore federal oil and natural gas leasing supported an average of 190 thousand jobs, generated $13.4 billion in labor income, and contributed $24.2 billion to GDP each year.

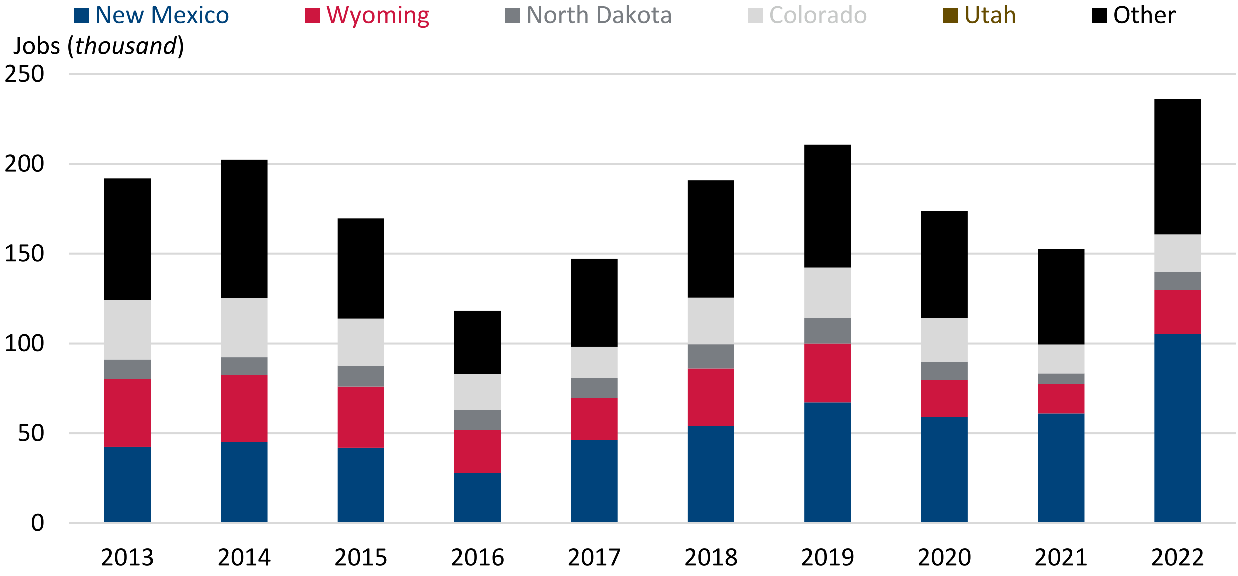
Figure 12. GDP Supported by Onshore Federal Oil & Natural Gas Leasing by FY



Sources: Bureau of Land Manegement; Rystad; IMPLAN; API calculations.

Notes: Includes benefits from production, drilling and development, and Federal revenue sharing. Revenue sharing supports state and local governments.

Figure 13. Jobs Supported by Onshore Federal Oil & Gas Leasing by FY



Source: BLM, Rystad, IMPLAN, API Calculatoins

Notes: Includes benefits from production, drilling and development, and Federal revenue sharing. Revenue sharing supports state and local govenments.

Conclusion

The development of oil and natural gas resources on onshore federal lands yields significant economic benefits. We find that in FY 2022, onshore federal oil and natural gas development supported nearly 250 thousand jobs, generated $19.4 billion in labor income, and contributed $36.7 billion to GDP. Between FY 2013 and FY 2022, we estimate that onshore federal oil and natural gas leasing supported an average of 190 thousand jobs, generated $13.4 billion in labor income, and contributed $24.2 billion to GDP each year.

From: Eric Delzer
To: Eric Delzer
Cc: Brady Pelton; Ron Ness; Reiten, John R.
Subject: Onshore Oil and Gas Leasing Final Rule
Date: Friday, April 12, 2024 3:42:49 PM
Attachments: Outlook-iviakooi.png
2023 09 22 Oand G Coalition Comments on BLM Proposed Leasing Rule Final Filed Comments and Benefits Report.pdf

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Good afternoon regulatory committee,

The Bureau of Land Management has released the final Onshore Oil and Gas Leasing Rule. It has been made available for public review but hasn't been published in the federal register. A copy of the final rule text can be found here.

NDPC joined over a dozen other trade partners in submitting 60 pages of comments (attached) in September of 2023. Upon initial review of the rule, none of our concerns appear to have been addressed in the final rule. The new provisions will make it very challenging economically to produce energy on federal lands.

The main changes in the final rule are:

- **Implementation of provisions of the Inflation Reduction Act (IRA)** pertaining to royalty rates, rentals, and minimum bids.
    - Royalty rate increased from 12.5% to 16.67% for new leases.
    - Reinstated leases increase to a minimum royalty rate of 20%

- **Updates to the bonding requirements** for leasing, development, and production.
    - Increases bond amount from $10,000 to $150,000.

- **Revisions to some operating requirements**, including:
    - Extending the term of an approved APD based on a lease suspension.
    - Requiring relocation of proposed operations by up to 800 meters to avoid resource conflicts.
    - Clarifying the process for modifying lease terms and stipulations.

- **Elimination of the formal lease nominations process**.
    - Replaced by a new "expression of interest" (EOI) process.

- **Addition of a new section addressing severability based on comment submissions**.

- **Updates to cross references and definitions throughout the regulations**.
    - Changed the “shall” to “may” to clarify that the Secretary retains the discretion to decide, even after lands have been determined to be eligible and available, what lands will ultimately be offered for lease.

- **Removal of "outdated" or "unnecessary" provisions**.

IPAA Statement on the new rule:

Dan Naatz, IPAA COO and EVP: "The final rule will not improve stewardship of federal lands, as BLM claims, but will have the effect of driving mineral production off of these areas. The regulatory environment has become so hostile to American oil and natural gas producers operating on federal land that it's clear the Biden Administration intends for "multiple use" lands to only be used for conservation and recreation. The true losers with this misguided policy are states and localities that rely on revenues from federal land extractive industries to meet their budget obligations year after year. Rather than taking their mandate to be good stewards of federal land for the betterment of the American people seriously, the Biden Administration continues to ignore the people in local towns and communities across the West in order to placate a small group of environmentalists and to further reduce American oil and natural gas production."

Here are some additional news stories from this afternoon regarding the rule.

Oil and gas companies must pay more to drill on federal lands under new Biden administration rule (msn.com)

Biden administration raises cost for oil and gas drilling on public lands for first time in decades - Washington Examiner

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
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100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Eric Delzer
To: Reiten, John R.; Ron Ness; Brady Pelton; Jonathan Fortner
Subject: Re: Public Lands Rule
Date: Tuesday, April 30, 2024 10:19:12 AM
Attachments: Outlook-p1oangdl.png

Thanks for sharing, John.

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PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Tuesday, April 30, 2024 9:36 AM
To: Ron Ness <ronness@ndoil.org>; Brady Pelton <bpelton@ndoil.org>; Eric Delzer <edelzer@ndoil.org>; Jonathan Fortner <JonathanFortner@lignite.com>
Subject: FW: Public Lands Rule

From: Cimiluca, Christine <ccimiluc@blm.gov>
Sent: Tuesday, April 30, 2024 9:12 AM
Subject: Public Lands Rule

Hello,

The Bureau of Land Management recently released its Public Lands Rule which aims to achieve multiple objectives, including the improvement of public land health and resilience in the face of climate change, the conservation of important wildlife habitat and intact landscapes, the facilitation of responsible development, and the recognition of unique cultural and natural resources.

To ensure effective implementation of the Public Lands Rule, the BLM

Montana/Dakotas has assembled a team of subject matter experts who will be available to deliver presentations and address any questions or concerns you may have. Your ongoing collaboration and support will be crucial as we navigate the implementation phase which will go into effect May 18, 2024.

As our valued partners and stakeholders, we invite you to engage with us in this endeavor and take advantage of the opportunity to have our team of experts present to your groups. These presentations will provide a comprehensive understanding of the rule, allowing you to actively participate in the conservation and management of our public lands. Together, we can ensure that these lands are passed on to future generations in as good or better shape than we found them.

If you'd like to schedule a meeting for a personalized presentation, please contact me with the following information:

- Preferred Time and Date
- Location
- In-person or Virtual
- Specific topics relevant to your organization

The Public Lands Rule comes at a crucial moment as our public lands face unprecedented challenges such as drought, wildfires, and the decline in their overall health. By managing for landscape health, the BLM aims to achieve its multiple use and sustained yield mission while prioritizing conservation as an essential component of public lands management.

To learn more about the rule and its specific provisions, I encourage you to review the detailed information provided on the Public Lands Rule website and in the final rule. This document outlines the objectives, processes, and benefits associated with the Public Lands Rule.

Thank you, and we look forward to hearing from you.

Take care,
Christine Cimiluca

Christine Cimiluca
Branch Chief, Climate, Environment and Planning
BLM Montana-Dakotas State Office
Work: (406)896-5110
Cell: (406)876-0912

United States Environmental Protection Agency

Regulatory Impact Analysis of the Proposed Waste Emissions Charge

EPA-430/R-23-005
January 2024

Regulatory Impact Analysis of the Proposed Waste Emissions Charge

U.S. Environmental Protection Agency
Office of Atmospheric Protection
Climate Change Division
Washington, DC

CONTACT INFORMATION

This document has been prepared by staff from the Office of Air and Radiation, U.S. Environmental Protection Agency, and Research Triangle International, Inc. Questions related to this document should be addressed to the Climate Change Division in the Office of Atmospheric Protection (email: merp@epa.gov).

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1 EXECUTIVE SUMMARY

This executive summary presents the results of the U.S. Environmental Protection Agency's (EPA) regulatory impact analysis (RIA) of the proposed rule implementing the methane waste emissions charge (WEC) required under the Inflation Reduction Act (IRA). The RIA is intended to provide the public with information on the relevant benefits and costs of this proposed rulemaking and to comply with executive orders, as well as other potential impacts of the rulemaking. This rulemaking proposes how EPA would implement the WEC according to the specifications in the IRA. Specifically, the rule proposes how the WEC will be calculated and how the exemption and netting provisions will function.

The WEC does not directly require emissions reductions from applicable facilities or emissions sources. However, by imposing a charge on methane emissions that exceed waste emissions thresholds, oil and natural gas facilities subject to the WEC are expected to perform methane mitigation actions and make operational changes where the costs of those changes are less than the WEC payments that would be avoided by reducing methane emissions. In addition, because volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions are emitted along with methane from oil and natural gas industry activities and are simultaneously reduced by methane mitigation actions, reductions in methane emissions as a result of the WEC also result in co-reductions of VOC and HAP emissions.

This RIA analyzes potential emissions changes and economic impacts of the WEC that arise through two pathways: 1) through the application of cost-effective methane mitigation technologies, and 2) through changes in oil and natural gas production resulting from price changes under the proposed rule. The analysis of methane mitigation is based on bottom-up engineering cost and mitigation potential information for a range of methane mitigation technologies. Application of methane mitigation technologies reduce WEC payments for WEC obligated parties by reducing methane emissions compared to a baseline without additional methane mitigation actions. The analysis assumes that methane mitigation is implemented where the engineering control costs are less than the avoided WEC payments for a particular mitigation technology.

Additionally, oil and natural gas firms may change their production and operational decisions in response to the WEC. This potential impact is modeled using a partial equilibrium

(PE) model of the crude oil and natural gas markets. The total cost of methane mitigation and WEC payments is added as an increase to production costs, resulting in changes in equilibrium production of oil and natural gas and associated emissions. Projected WEC payments are estimated after methane emissions reductions from both methane mitigation and economic impacts are accounted for.

Using emissions reported to Subpart W for Reporting Year (RY) 2021 as an illustrative example, Table 1-1 shows that the WEC would be imposed on less than 15 percent of national methane emissions from petroleum and natural gas systems. Total methane emissions reported to the Greenhouse Gas Reporting Program (GHGRP) Subpart W are significantly less than national methane emissions from the U.S. Greenhouse Gas Inventory for petroleum and natural gas systems. WEC-applicable facilities are the subset of GHGRP facilities that report at least 25 thousand metric tons CO_2e to Subpart W segments subject to the WEC.

It is also important to note that the WEC would only apply to methane emissions that are above the emissions threshold, not for all emissions from WEC-applicable facilities. The WEC has exemptions related to regulatory compliance, emissions from plugged wells, and unreasonable delay in environmental permitting, although these provisions do not impact the illustrative results in Table 1-1. Finally, emissions subject to WEC accounts for netting of emissions between facilities. Under the proposed WEC, facilities with emissions below their emissions threshold may reduce emissions subject to the WEC at other facilities with emissions above the emissions threshold where those facilities are under common ownership or control.

Table 1-1 Emissions Subject to the WEC

	CH_4 emissions, 2021	
	(thousand metric tons)	**($MMTCO_2$e with GWP=28)**
Petroleum and Natural Gas Systems National Total (GHGI)	8,600	240
GHGRP Subpart W	2,800	79
From WEC-applicable facilities (>25,000 $mtCO_2$e to W)	2,100	60
Facility emissions exceeding emissions threshold	1,200	33
Emissions subject to WEC, after netting	1,000	29

The benefit-cost analysis contained in this RIA for the WEC considers the potential benefits and costs of the WEC arising from cost-effective mitigation actions under the WEC as well as the potential transfers from affected operators to the government in payments. Costs include engineering costs for methane mitigation actions and costs resulting from production changes in oil and natural gas markets under the rule. While EPA expects a range of health and environmental benefits from reductions in methane, VOC, and HAP emissions under the WEC, the monetized benefits of the rule are limited to the estimated climate benefits from projected methane emissions reductions. These benefit estimates are based on the social cost of methane (SC-CH_4). A screening-level analysis of ozone-related benefits from projected VOC reductions can be found in Appendix A of the RIA. However, these estimates are treated as illustrative and are not included in the quantified benefit-cost comparisons in the RIA.

EPA estimates that this action will result in cumulative emissions reductions of 960 thousand metric tons of methane over the 2024 to 2035 period. These reductions represent about 33 percent of methane emissions that would be subject to the WEC before accounting for the adoption of cost-effective emission reduction technologies. Virtually all the reduced emissions result from mitigation activities undertaken by industry to reduce WEC payments. Less than 1 percent of the estimated reductions is associated with decreased production activity in the oil and natural gas sector estimated under the proposed rule. In addition to methane emissions reductions, the WEC is estimated to result in reductions of 140 thousand metric tons of VOC and 5 thousand metric tons of HAP over the 2024 to 2035 period.

Table 1-2 Projected Emissions Reductions from the Proposed Waste Emissions Charge, 2024-2035

	Emission Changes			
	Methane (thousand metric tons)	**VOC (thousand metric tons)**	**HAP (thousand metric tons)**	**Methane (million metric tons CO_2 Eq. using GWP=28)**
Total	960	140	5	27

The WEC has important interactions and is designed to work hand-in-hand with the New Source Performance Standards (NSPS OOOb) and Emissions Guidelines (EG OOOOc) for the Oil and Natural Gas Sector by accelerating the adoption of cost-effective methane mitigation technologies, including those that would eventually be required under the NSPS OOOOb or EG OOOOc. The annual projected emissions reductions, costs, and WEC obligations are significantly affected by these interactions.

The EPA proposed updates to the Oil and Gas NSPS OOOOb/EG OOOOc in 2021, published a supplemental proposal in 2022, and finalized the NSPS OOOOb/EG OOOOc in December 2023. In addition to requirements already in place, these rules include standards for many of the major sources of methane emissions in the oil and natural gas industry. To avoid double counting of benefits and costs, the baseline for this proposal includes reductions resulting from the NSPS OOOOb/EG OOOOc based on information from the 2023 Final RIA. Specifically, that analysis showed methane emissions reductions from the EG OOOOc beginning to take effect in 2028. As facilities implement emission controls required by the NSPS OOOOb and EG OOOOc, emissions subject to the WEC decline.

The second interaction between the WEC and NSPS OOOOb/EG OOOOc is the regulatory compliance exemption provision of the WEC. Under this provision, when certain conditions are met with respect to the implementation of the Oil and Natural Gas NSPS OOOOb/EG OOOOc, applicable facilities in compliance with the NSPS OOOOb/EG OOOOc are exempted from the WEC. The analysis in this RIA assumes that the regulatory compliance exemption takes effect in 2027, such that, in 2027 and later, facilities in the industry segments subject to requirements under the NSPS OOOOb/EG OOOOc do not owe WEC payments.

Projected methane emissions subject to WEC after accounting for methane mitigation and energy market impacts are estimated to be about 830 thousand metric tons in 2024, and then drop significantly the regulatory compliance exemption takes effect in 2027. Table 1-3 provides projected WEC-applicable emissions in the baseline and policy scenario.

Table 1-3 Projected Net WEC Emissions and WEC Obligations in the Policy Scenario

Year	Methane Emissions Subject to WEC in Baseline (thousand metric tons)	Reductions from Methane Mitigation (thousand metric tons)	Reductions from Energy Market Impacts (thousand metric tons)	Methane Emissions Subject to WEC in Policy Scenario (thousand metric tons)
2024	980	150	0.1	830
2025	940	300	0.1	650
2026	900	470	2.0	430
2027	13	5	0.0	8.6
2028	13	5	0.0	8.5
2029	13	5	0.0	8.5
2030	13	5	0.0	8.5
2031	13	5	0.0	8.5
2032	13	5	0.0	8.4
2033	13	5	0.0	8.4

Year	Methane Emissions Subject to WEC in Baseline (thousand metric tons)	Reductions from Methane Mitigation (thousand metric tons)	Reductions from Energy Market Impacts (thousand metric tons)	Methane Emissions Subject to WEC in Policy Scenario (thousand metric tons)
2034	13	5	0.0	8.4
2035	13	5	0.0	8.3
Total 2024-2035	2,900	960	2.6	2,000

Climate benefits associated with this proposed rule are monetized using estimates of the social cost of methane (SC-CH_4) which calculates the avoided climate related damages from reducing methane emissions. Methane is the principal component of natural gas. As a potent GHG, methane absorbs terrestrial infrared radiation once emitted into the atmosphere, which in turn contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone, which also impacts global temperatures. In addition to other GHG emissions, methane contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice sheets, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

This proposed rulemaking is projected to reduce VOC emissions, which are a precursor to ozone. Ozone is not generally emitted directly into the atmosphere but is created when its two primary precursors, VOC and oxides of nitrogen (NO_X), react in the atmosphere in the presence of sunlight. Emissions reductions under the WEC may decrease ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. VOC emissions are also a precursor to $PM_{2.5}$, so VOC reductions may also decrease human exposure to $PM_{2.5}$ and the incidence of $PM_{2.5}$- related health effects.

Available emissions data show that several different HAP are emitted from oil and natural gas operations. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and natural gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4- trimethylpentane (U.S. EPA, 2011b). Reductions of HAP emissions under the WEC may reduce exposure to these and other HAP.

In Section 9.3 of the RIA, EPA identifies existing potential environmental justice issues for the communities in counties that have emissions sources that are expected to owe the WEC charge and thus may be positively affected by emissions changes under the proposal. Compared to the national average, these communities include a higher percentage of individuals who identify as racial and ethnic minorities, have lower average incomes, and have slightly elevated health risks associated with various air emissions. Reductions in VOC and HAP emissions as a result of the WEC are expected to benefit communities in these counties. Because the WEC does not directly require emissions reductions, EPA has not projected specific locations that emissions reductions might occur. In addition, detailed proximity analysis is infeasible because the emissions affected by the WEC occur at hundreds of thousands of locations.

The total cost of the proposed rule includes the engineering costs for methane mitigation actions implemented by the oil and natural gas industry to reduce WEC obligations. This includes the initial capital costs required to implement and install the specific mitigation technology. In addition, for mitigation technologies with expected lifetimes greater than one-year, annual recurring operations and maintenance (O&M) costs which include labor, energy and materials are also incorporated. Finally, the total mitigation costs also include the avoided cost of natural gas losses.

The social cost of energy market impacts is the loss in consumer and producer surplus value from changes in natural gas market production and prices. The economic impacts analysis uses a partial equilibrium model and estimates that the impact of the gas market is minimal, with the largest impact occurring in the first few years with a price increase of less than 0.1% and a quantity reduction of less than 0.1%.

Table 1-4 presents results of the benefit-cost analysis for the proposed WEC. The table presents the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 2, 3, and 7 percent, of the changes in quantified benefits, costs, and net benefits relative to the baseline.[1] These values reflect an analytical time horizon of 2024 to 2035, are discounted

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[1] Monetized climate effects are presented under a 2 percent near-term Ramsey discount rate, consistent with EPA's updated estimates of the SC-GHG. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. While this RIA was being drafted, OMB

to 2023, and are presented in 2019 constant dollars. The table includes consideration of the non-monetized benefits associated with the emissions reductions projected under this proposal.[2]

Table 1-4 Projected Benefits and Costs from the Proposed Waste Emissions Charge (million 2019$)

	2 Percent Near-Term Ramsey Discount Rate					
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Monetized Climate Benefits[a]	$1,900	$180	$1,900	$180	$1,900	$180
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Total Social Costs	$390	$37	$380	$38	$340	$43
Cost of Methane Mitigation	$360	$34	$350	$35	$320	$40
Cost of Energy Market Impacts	$30	$3	$29	$3	$26	$3
Net Benefits[b]	$1,500	$140	$1,500	$140	$1,600	$140
Non-Monetized Benefits	Ozone benefits from reducing 960 thousand metric tons of methane from 2024 to 2035 PM2.5 and ozone health benefits from reducing 140 thousand metric tons of VOC from 2024 to 2035 HAP benefits from reducing 5 metric tons of HAP from 2024 to 2035 Visibility benefits Reduced vegetation effects					

[a] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Table 6-5 for the full range of monetized climate benefit estimates.

[b] Several categories of climate, human health, and welfare benefits from methane, VOC, and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in the table. See Section 6.1 for a discussion of climate effects that are not yet reflected in the SC-CH_4 and thus remain

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finalized an update to Circular A-4, in which it recommended the general application of a 2.0 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC-GHG estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the discount rate estimated using the average return on capital (7 percent in OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG. See Section 6.1 for more discussion.

[2] As discussed in Section 6 of this RIA, the monetized benefits estimates provide an incomplete overview of the beneficial impacts of the proposal. In particular, the monetized climate benefits are incomplete and an underestimate as explained in Section 6.1. In addition, important health and welfare benefits anticipated under these proposed rules are not quantified or monetized. EPA anticipates that taking non-monetized effects into account would show the proposals to have greater benefit than the tables in this section reflect. Simultaneously, the estimates of costs used in the net benefits analysis may provide an incomplete characterization of the true costs of the rule. The balance of unquantified benefits and costs is ambiguous but is unlikely to change the result that the benefits of the proposal exceed the costs.

unmonetized and Section 6.2 for a discussion of other non-monetized benefits. A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix A of the RIA.

WEC payments are transfers and do not affect total net benefits to society as a whole because payments by oil and natural gas operators are offset by receipts by the government. Therefore, from a net-benefit accounting perspective, transfers are considered separately from costs and benefits (and are therefore not included in Table 1-4). As explained further in Section 2.7, the approach taken here is in line with OMB guidance and the approach taken for RIAs for other rules impacting payments to the government, such as the Bureau of Land Management (BLM)'s waste prevention rule.

One of the reasons that transfers are not considered costs is because they represent payments to the U.S. Treasury that do not affect total resources available to society. Payments to the U.S. Treasury can then be used to fund other programs, and the pairing of revenue collection (e.g., the WEC payments) with commensurate expenditures (e.g., financial assistance programs) by the federal government can be designed to be revenue neutral. The Methane Emission Reduction Program created under CAA section 136 includes both collection and expenditure components. In addition to establishing the WEC, another key purpose of CAA section 136 is to encourage the development of innovative technologies in the detection and mitigation of methane emissions. See 168 Cong. Rec. E869 (August 23, 2022) (statement of Rep. Frank Pallone). CAA section 136(a) and (b) provides $1.55 billion to, among other things, help finance the early adoption of emissions reduction methodologies and technologies and to support monitoring of methane emissions. These incentives for methane mitigation and monitoring complement the WEC.

The WEC has the effect of better aligning the economic incentives of oil and natural gas companies with the costs and benefits faced by society from oil and gas activities. In the baseline scenario the environmental damages resulting from methane emissions from the oil and gas sector are a negative externality spread across society as a whole. Under the WEC, this negative externality is internalized, oil and gas companies are required to make WEC payments in proportion to the climate damages of methane emissions subject to the WEC.[3] Alternatively,

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[3] Note that Congress specified that the WEC would rise to $1,500 per metric ton of methane in 2026 and beyond. This value is consistent with estimates of climate damages associated with emissions of a metric ton of methane

firms can avoid making WEC payments by mitigating their emissions generating climate benefits associated with the amount of mitigation.

Table 1-5 provides details of the calculation steps used to estimate projected WEC obligations and climate damages based on projected emission subject to WEC. In order to compare projected WEC payments to climate damages from emissions subject to the WEC, WEC payments are converted from nominal dollars to 2019 constant dollars using a chain-weighted GDP price index from the 2023 Annual Energy Outlook (EIA, 2023).

Table 1-5 Details of Projected WEC Obligations and Climate Damages from Emissions Subject to WEC (million 2019$)

Year	Methane Emissions Subject to WEC in Policy Scenario (thousand metric tons)	Charge Specified by Congress (nominal $ per metric ton)	WEC Payments in Policy Scenario (million nominal $)	WEC Payments in Policy Scenario (million 2019$)	SC-CH_4 Values under 2% Near-Term Discount Rate (2019$ per metric ton)	Climate Damages from Emissions Subject to WEC (million 2019$)[a]
2024	830	$900	$750	$620	$1,900	$1,600
2025	650	$1,200	$770	$630	$2,000	$1,300
2026	430	$1,500	$640	$510	$2,100	$890
2027	9	$1,500	$13	$10	$2,200	$18
2028	9	$1,500	$13	$10	$2,200	$19
2029	9	$1,500	$13	$10	$2,300	$20
2030	9	$1,500	$13	$9	$2,400	$20
2031	9	$1,500	$13	$9	$2,500	$21
2032	9	$1,500	$13	$9	$2,500	$21
2033	8	$1,500	$13	$9	$2,600	$21
2034	8	$1,500	$13	$8	$2,700	$21
2035	8	$1,500	$13	$8	$2,800	$21
Total 2024-2035	2,000	-	$2,300	$1,800	-	$4,000

[a] Climate damages are based on remaining methane emissions subject to WEC after accounting for emissions reductions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate.

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that were available at the time the IRA was passed. The February 2021, 'Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990,' estimated that the social cost of CH4 under a 3% discount rate for emissions occuring in the year 2020 was $1,500.

2 BACKGROUND AND OVERVIEW

2.1 Introduction

This document presents the regulatory impact analysis (RIA) for the notice of proposed rulemaking titled “Waste Emissions Charge for Petroleum and Natural Gas Systems.” The proposed rulemaking would implement a waste emissions charge (WEC) for methane (CH_4) emissions that are reported by applicable facilities to EPA under Greenhouse Gas Reporting Program (GHGRP) Subpart W and exceed emissions intensity thresholds. The proposal responds to requirements from the Inflation Reduction Act.

2.2 Statutory Requirements

This section describes the legal basis for the proposed WEC. The Inflation Reduction Act (IRA), signed into law on August 16, 2022, introduced new requirements for methane emissions from petroleum and natural gas systems, including a Waste Emission Charge (WEC). Section 60113 of the Inflation Reduction Act added section 136 to the CAA, entitled “Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems.” Section 136(c) of the CAA, “Waste Emissions Charge, states, “The Administrator shall impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W of part 98 of title 40, Code of Federal Regulations, regardless of the reporting threshold under that subpart.” Other key sections of the CAA that define the requirements of the methane emissions and waste reduction incentive program include the following:

- Section 136(d) of the CAA, “Applicable Facility,” defines the term applicable facility for the purposes of section 136.
- CAA section 136(e), “Charge Amount,” specifies that the waste emissions charge is determined by multiplying methane emissions reported to subpart W by specified charge rates for calendar year 2024, calendar year 2025, and calendar year 2026 and each year thereafter.
- CAA section 136(f), “Waste Emissions Threshold,” establishes the thresholds by industry segment above which the EPA must impose and collect the CH_4 emissions charge. The subsection also provides that the EPA shall allow for the netting of emissions for certain facilities under common ownership or control and provides for several exemptions from charges.

- CAA section 136(g) mandates that the waste emissions charge shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter.

The charge per metric ton of methane emitted in excess of the industry segment-specific threshold increases according to the following schedule, as specified in the IRA: $900 in calendar year 2024, $1,200 in 2025, and $1,500 in 2026 and beyond. Thresholds are set based on industry segments and activities conducted at the facility. The waste emissions threshold is a facility-specific amount of metric tons of methane emissions calculated using the segment-specific methane intensity thresholds and a facility's natural gas throughput (or oil throughput in certain circumstances); facilities that have methane emissions below the threshold would not be required to pay the charge. It is also important to note that the WEC would only apply to the subset of methane emissions that are above the emission threshold, not for a facility's total methane emissions. The emission thresholds for each industry segment-specific are specified in CAA section 136(f), which are shown in Table 2-1 .

Table 2-1 Waste Emissions Thresholds by Industry Segment in CAA Section 136(f)

Industry Segments	Applicable Waste Emissions Threshold, Calculated as the Metric Tons of Methane Emissions Equal to:
Onshore petroleum and natural gas production Offshore petroleum and natural gas production	0.20 percent of the natural gas sent to sale from the facility; OR 10 metric tons of methane per million barrels of oil sent to sale from such facility, if the facility sent no natural gas to sale
Onshore petroleum and natural gas gathering and boosting Onshore natural gas processing Liquefied natural gas storage Liquefied natural gas import and export equipment	0.05 percent of the natural gas sent to sale from or through the facility
Onshore natural gas transmission compression Underground natural gas storage Onshore natural gas transmission pipeline	0.11 percent of the natural gas sent to sale from or through the facility

The EPA is proposing to establish provisions for the WEC at 40 CFR part 99 consistent with the authority and directives set forth in CAA section 136(c) through (g). This proposed rulemaking is hereafter referred to as the "WEC proposal" and the proposed provisions under 40 CFR part 99 are hereafter referred to as "proposed WEC regulations."

For petroleum and natural gas systems, the Greenhouse Gas Reporting Program currently requires that owners or operators of facilities that emit 25,000 metric tons (mt) or more of greenhouse gases (GHGs) per year in combined emissions from all applicable source categories (expressed as carbon dioxide equivalents (CO_2e)) must report GHG data to the GHGRP according to the requirements of subpart W. Subpart W applies to each of the following ten industry segments:

- **Onshore Petroleum and Natural Gas Production**: Production of petroleum and natural gas associated with onshore production wells and related equipment.
- **Offshore Petroleum and Natural Gas Production**: Production of petroleum and natural gas from offshore production platforms.
- **Onshore Petroleum and Natural Gas Gathering and Boosting**: Gathering pipelines and other equipment used to collect petroleum/natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum/natural gas.
- **Onshore Natural Gas Processing**: Processing of field-quality gas to produce pipeline-quality natural gas, processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 million standard cubic feet per day (MMscf/day) or greater.
- **Onshore Natural Gas Transmission Compression**: Compressor stations used to transfer natural gas through transmission pipelines.
- **Onshore Natural Gas Transmission Pipeline**: All natural gas transmission pipelines as defined in §98.238 (a rate-regulated interstate or intrastate pipeline, or a pipeline that falls under the "Hinshaw Exemption" of the Natural Gas Act).
- **Underground Natural Gas Storage**: Facilities that store natural gas in underground formations.
- **Liquefied Natural Gas (LNG) Storage**: LNG storage equipment.
- **LNG Import/Export**: LNG import and export terminals.
- **Natural Gas Distribution**: Distribution systems that deliver natural gas to customers.[4]

Consistent with Section 136(d) of the CAA, we are proposing to define a “WEC applicable facility” as a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 and listed above (i.e., all subpart W industry segments except natural gas distribution) for which the owner or operator of the subpart W reporting facility reports subpart W emissions of more than 25,000 metric tons CO_2e. The EPA is

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[4] The Natural Gas Distribution segment is not included in CAA section 136 and is therefore not discussed further in this document.

proposing that WEC would be imposed for each WEC obligated party, which is defined in the proposed rule as the owners or operators of one or more WEC applicable facilities.

2.3 Relationship to Other Requirements Impacting Methane Emissions

In addition to the Waste Emissions Charge, the EPA is currently undertaking several other actions that impact methane emissions from the oil and natural gas industry, and therefore influence the results presented in this RIA. In particular, the WEC has important interactions with revisions to GHGRP Subpart W and the New Source Performance Standards and Emissions Guidelines (NSPS OOOOb/EG OOOOc) for the Oil and Natural Gas Sector.

The Inflation Reduction Act mandates that the WEC calculations be based on methane emissions reported to GHGRP Subpart W. Section 136(h) of the CAA requires that the EPA revise the requirements of subpart W within two years after the date of enactment of section 60113 of the IRA to ensure that WEC calculations "are based on empirical data, … accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data." On August 1, 2023, the EPA proposed revisions to the requirements of subpart W consistent with those directives (88 FR 50282). Those revisions, when finalized, would be used to report emissions to GHGRP and impact the resulting WEC calculations. However, those amendments would become effective on January 1, 2025, and reporters would implement the majority of the changes beginning with reports prepared for Reporting Year (RY) 2025, which are due March 31, 2026. Because CAA section 136(c) requires the Administrator to impose and collect the WEC beginning with emissions as reported for calendar year 2024, the first year that the WEC will be collected will be based on the current provisions of subpart W. The analysis in this RIA is based on current reported emissions and current methods and factors rather than these proposed amendments.

The GHGRP subpart W revisions make changes that may significantly affect reported emissions, but the specific changes are difficult to estimate, particularly at the specificity needed to estimate WEC payments. For example, the proposed revisions add a new emissions source, "other large release events." Other large release events are believed to occur sporadically at a minority of facilities, but with potentially significant emissions when they occur.[5] The EPA also proposed revisions to add new calculation methods incorporating additional empirical data and measurements. Calculation methods based on facility- or company-specific measurements may lead to significantly different emissions reported depending on the particular conditions at each facility. In order to estimate WEC payments, reported emissions for each facility and WEC obligated party must be compared against waste emissions thresholds. In lieu of highly uncertain estimates of how revised GHGRP methods may impact reported emissions, the calculations in this RIA are mainly based on current reported emissions. Section 8.1 includes a qualitative discussion of potential sensitivity of this analysis to changes in reported emissions from proposed GHGRP Subpart W revisions.

The WEC also has important interactions and is designed to work hand-in-hand with the Oil and Gas NSPS OOOOb and EG OOOOc. The EPA proposed updates to the Oil and Gas NSPS OOOOb/EG OOOOc in 2021, published a supplemental proposal in 2022, and finalized in December 2023. In addition to requirements already in place, these rules include standards for many of the major sources of methane emissions in the oil and natural gas industry. The revised NSPS OOOOb/EG OOOOc includes new requirements for new and modified facilities and requirements for existing sources, which are to be implemented by the states via state regulations and state implementation plans. The first way that the WEC interacts with the NSPS OOOOb/EG OOOOc is the significant overlap in the emissions impacted by the two policies. Some oil and gas operations are subject to emissions reporting under GHGRP subpart W and are also subject to the requirements of the NSPS OOOOb/EG OOOOc. As WEC obligated parties implement the emissions controls required by the NSPS OOOOb/EG OOOOc, the resulting reduced emissions would also mean reduced WEC payments. This RIA accounts for this interaction by including the emissions reduction impacts of the Oil and Gas NSPS OOOOb/EG OOOOc in the baseline scenario.

The second interaction between the WEC and NSPS OOOOb/EG OOOOc is the regulatory compliance exemption provision of the WEC. Under this provision, when certain

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[5] EPA does not have an estimate of the number of large release events or quantity of emissions which may be reported under the proposed source category. EPA described available information regarding some event types, such as well blowouts, in section 3 of the technical support document for the GHGRP Subpart W revisions, available here: https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0163

conditions are met with respect to the implementation of the Oil and Gas NSPS OOOOb/EG OOOOc, applicable facilities in compliance with the NSPS OOOOb and EG OOOOc requirements that would otherwise be subject to charge are exempted from the WEC. The analysis in this RIA assumes that the regulatory compliance exemption provision takes effect in 2027, such that in 2027 and later, facilities in the industry segments subject to requirements under the NSPS OOOOb/EG OOOOc do not owe WEC payments.[6] The Final Oil and Natural Gas NSPS OOOOb/EG OOOOc lays out the timing for state plan submission. Under the EG OOOOc, states have 24 months to submit their state implementation plans, and EPA must approve or deny state plans within 12 months, which means that the regulatory compliance exemption could be available as early as January 2027, assuming no Federal Implementation Plan is needed.

2.4 Economic Basis for the Rulemaking

This section describes the economic rationale for the proposed WEC. Market failures occur when free market interactions lead to a suboptimal allocation of resources. The core market failure addressed by section 136 (c) of the Inflation Reduction Act is the externality of climate damage from methane emissions. As described in more detail in the Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, producers contribute to climate change when extracting, processing, and transporting petroleum and natural gas products. The producers spread the costs of these actions to society as a whole by lowering the availability of public goods, such as better air quality or less severe effects of climate change, while reaping the financial benefits themselves.

The WEC attempts to address the market failure by imposing a charge on petroleum and natural gas producers that emit above a certain threshold of methane. In the absence of the WEC,

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[6] The analysis in this RIA assumes that all facilities in the industry segments subject to NSPS/EG requirements are eligible for the regulatory compliance exemption in 2027 and thereafter. We recognize that not all facilities will be eligible because of compliance issues. However, EPA does not have the capability to predict how many facilities this situation will affect. Furthermore, the existence of the regulatory compliance provision may have a beneficial effect on regulatory compliance. The assumption of full compliance is a simplifying assumption for analysis purposes.

the discrepancy in public and private costs means the socially optimal level of methane emissions is misaligned with the optimal level of methane emissions for petroleum and natural gas facilities operated by private companies. The proposed WEC attempts to bring the level of methane emissions that is optimal for producers in the oil and gas sector closer to the socially optimal level of methane emissions. Through this policy, oil and natural gas companies subject to the WEC internalize costs associated with environmental damages of remaining methane emissions. The WEC properly aligns private incentives: to the extent that companies subject to the WEC are able to mitigate their emissions, they can both reduce WEC payments and the environmental damages that result from emissions. In the absence of environmental policies, oil and natural gas producers already have economic incentives to mitigate fugitive methane emissions because those emissions represent loss of a saleable product, natural gas. Where mitigation actions cost less than expected revenue from recovered natural gas, a substantial portion of those actions are likely to be taken up voluntarily. However, this product revenue incentive does not account for external environmental damages. Where the mitigation costs exceed expected product revenue, energy market incentives alone would not likely be sufficient to induce socially optimal mitigation actions. Estimation of breakeven costs for methane mitigation actions is further discussed in section 5. Furthermore, as described in section 7, total projected WEC payments are less than the total projected damages associated with emissions subject to the WEC.

2.5 Analysis Overview

As described in section 2.2, CAA section 136(c) states that a WEC will be levied on methane emissions that exceed statutorily specified waste emissions thresholds from an owner or operator of an applicable facility. The waste emissions threshold is a methane intensity metric, therefore facilities that have methane emissions per unit of throughput below the threshold would not be required to pay the charge. The WEC only applies to the subset of a facility’s emissions that are above the waste emissions threshold.

For this analysis it is assumed that the applicable facilities facing the WEC on emissions that exceed the waste emissions threshold will make an economic choice to invest in mitigation measures that reduce their emissions, thereby reducing the WEC obligation. While many facilities will likely find it less expensive to reduce their emissions via mitigation technology, there will be facilities where the cost of reducing emissions is higher than the WEC charges. In the latter case, it is assumed that the facility will elect to pay the WEC rather than invest in more costly mitigation technology.

The regulatory impacts of the proposed WEC are evaluated relative to a baseline that represents the oil and gas industry in the absence of this proposed action. To avoid double counting of costs, the baseline for this proposal includes reductions resulting from the NSPS OOOOb/EG OOOOc for Oil and Gas, as detailed in the Final NSPS OOOOb/EG OOOOc RIA. Only a subset of the baseline emissions is subject to the WEC, as seen in section 4.2.

The impact analysis relies in part on the marginal abatement cost curve (MACC) for the oil and gas industry, which is further discussed in section 7. The MACC model is a mitigation cost model that EPA developed to model methane mitigation potential from U.S. oil and natural gas systems as part of larger analyses of non-CO_2 GHG emissions projection and mitigation potential for over 20 years[7]. The MACC is used to estimate what methane mitigation could be expected as a result of facilities facing the WEC charges deciding to adopt mitigation measures earlier than they would have under the NSPS OOOOb/EG OOOOc rule. The flat charge per metric ton of methane suggests that some facilities may find it cheaper to adopt methane emission controls in early years to reduce or avoid WEC obligations while other facilities will find it cheaper to pay the WEC. The analysis used EPA's national oil and gas system MACC model to evaluate the potential emissions reductions likely to occur each year from facilities where mitigation technology would be cheaper than paying the WEC charges.

For this analysis, EPA updated the mitigation options technologies characterized in the model to reflect the most recently published best system of emission reduction (BSER) estimates of emissions reduction performance and costs. Additional information on the mitigation technologies updated for this analysis is available in Appendix C.

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[7] For additional information on the MACC model and its modeling framework see Global Non-CO2 Greenhouse Gas Emissions Projections & Marginal Abatement Cost Analysis: Methodology Documentation. EPA-430-R-19-012.

2.6 Economic Significance

The proposed Waste Emissions Charge constitutes a “significant regulatory action” as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Executive Order 12866 requires agencies to conduct regulatory analysis for actions that are significant under Section 3(f)(1) (as amended). Actions that are significant under Section 3(f)(1) include actions likely to result in annual costs, benefits, or transfers of at least $200 million per year. As discussion in Section 1, the emissions reductions projected under the rule are likely to produce substantial climate benefits, peaking at $780 million to $1.3 billion in 2026, as well as non-monetized benefits from reductions in VOC and HAP emissions. At the same time, the proposed WEC is projected to result in substantial transfer payments by the oil and gas industry to comply with the rule, reaching a maximum of $770 million in 2025.

2.7 Transfers

From the perspective of calculating costs and benefits that accrue to society as a whole, WEC payments are transfers payments. Transfer payments are a shift in money from one party to another. On net, transfers do not affect total net benefits because payments by one group are offset by receipts by another group. In the case of the WEC, payments made by oil and gas operators are offset by receipts by the government in the societal cost benefit analysis. From OMB Circular A-4 (2003) and OMB Circular A-4 (2023), transfer payments potentially include fees to government agencies for goods and services, tax payments from individuals or businesses to the government (monetary transfers to the government) and tax refunds from the government (monetary transfers from the government to taxpayers). (OMB, 2003, 2023)

The approach taken here is in line with the approach taken for regulatory impact analyses for other rules impacting payments to the government. For example, in the BLM’s waste prevention rule, royalty payments were treated as transfers because they are income for the Federal or Tribal government and costs to the operator or lessee. (BLM, 2022) In an EPA rule modifying fees related to administration of the Toxic Substance Control Act, the total social cost did not include the fees incurred by firms and collected by EPA, as those fees represent a transfer from affected manufacturers and processors to taxpayers. (USEPA, 2018)

There are two accounting approaches that can be used to quantify transfers in regulatory impact analyses. (OMB, 2023) First, transfers can be accounted for separately from costs and benefits. A second approach is to include one side of a transfer as a benefit and the other side of a transfer as a cost, such that the transfer is treated symmetrically in the estimate of net benefits. In the comparison of costs and benefits in this RIA, we use the first approach and do not include the transfer amount in either the benefits or costs.

Although WEC payments are transfers from the perspective of societal costs and benefits, for the purpose of analyses focused on impacts on oil and gas companies subject to the WEC, payments are included. In the energy markets analysis, both costs of methane mitigation and WEC payments impact production and operation costs and result in changes in equilibrium prices and production. In the small business analysis, WEC payments are the focus of the analysis of costs for small entities under this program.

2.8 Organization of RIA

The remainder of the RIA is organized as follows:

- **Section 3, Baseline**, describes the baseline projection of CH_4 emissions reported to Subpart W for segments subject to the Waste Emissions Charge.
- **Section 4, WEC Scenario** describes the policy scenario analyzed, WEC applicable facilities, and the calculation steps for emissions subject to the WEC**.**
- **Section 5, Costs and Emissions Impacts** describes the costs and emissions impacts of the two major responses to the WEC: 1) application of methane mitigation technologies, and 2) energy market changes in oil and gas production and prices. This section includes descriptions of the marginal abatement cost analysis, and the partial equilibrium model used for market modeling.
- **Section 6, Benefits**, describes the methods used to estimate the climate benefits from reductions of CH_4 emissions. This analysis uses estimates of the social cost of greenhouse gases to monetize the estimated changes in CH_4 emissions expected to occur over 2024 through 2035 for the proposed rule. Qualitative benefits of VOC and HAP reductions are also discussed.
- **Section 7**, **Comparison of Benefits and Costs**: presents estimates of the net benefits of the rule.
- **Section 8, Uncertainty Analyses**: discusses sensitivity of results related to GHGRP calculation methods and potential interaction with NSPS OOOOb/EG OOOOc.
- **Section 9, Distributional and Economic Analyses:** presents the small business, employment, environmental justice, and distributional climate impacts analyses.

3 BASELINE

3.1 Baseline Projection Approach

This section describes the baseline projection of CH_4 emissions and throughput reported to GHGRP Subpart W for segments subject to the Waste Emissions Charge, from the base year 2021 through 2035. The baseline is used to estimate facilities and emissions potentially subject to the Waste Emissions Charge and as an input to the mitigation analysis. The baseline begins from emissions and activity reported to Subpart W in RY 2021. Emissions trends are projected by segment, source, control status, and site types.

The baseline projection includes anticipated impacts from the Oil and Gas NSPS OOOOb/EG OOOOc. This approach is taken to avoid double-counting of costs and emissions reductions across the analyses for the NSPS OOOOb/EG OOOOc and WEC. This analysis has been updated to reflect the 2023 final RIA for the NSPS OOOOb/EG OOOOc.

3.1.1 Base Year Emissions by Segment and Source

The baseline analysis begins from detailed GHGRP Subpart W reported data by facility, segment, source, and unit type. The baseline scope is CH_4 emissions reported under segments subject to the WEC.[8] Detailed reporting data on throughput and emissions is necessary to estimate potential WEC amounts and emissions reductions resulting from the WEC, because the WEC is assessed by facility and owner or operator ("WEC obligated party" for netting across facilities). As shown in Table 2-1, emissions reported to Subpart W are broken out by source and unit type in order to assess mitigation potential for each emissions source and equipment type independently. Further detail on Subpart W emissions reported by segment, source, and trends over time can be found in the GHGRP sector profile for petroleum and natural gas systems.[9]

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[8] GHGRP Subpart W segments subject to the WEC are onshore production, offshore production, gathering and boosting, gas processing, transmission compression, transmission pipelines, natural gas storage, LNG import/export, and LNG storage. The NG distribution segment is not subject to the WEC.

[9] 2011-2021 Greenhouse Gas Reporting Program Industrial Profile: Petroleum and Natural Gas Systems, reflecting the same data snapshot used in this analysis, available here: https://www.epa.gov/system/files/documents/2022-10/subpart_w_2021_sector_profile.pdf

Table 3-1 Methane Emissions Reported to Subpart W Segments Subject to the WEC, By Source and Unit Type (RY 2021)

Source	Unit Type	CH_4 tons
Pneumatic Devices	Intermittent Bleed Pneumatic Devices	919,000
Misc Equipment Leaks	Equipment Leak Population Counts	396,000
Blowdown Vent Stacks		238,000
Pneumatic Pumps		83,000
Dehydrators		80,000
Liquids Unloading		74,000
Pneumatic Devices	High-Bleed Pneumatic Devices	69,000
Reciprocating Compressors	Reciprocating Compressors - Rod Packing	59,000
Centrifugal Compressors	Wet Seal Centrifugal Compressors - Seals	56,000
Combustion Equipment		55,000
Other Flare Stacks		48,000
Atmospheric Storage Tanks		47,000
Offshore Sources		47,000
Pneumatic Devices	Low-Bleed Pneumatic Devices	42,000
Associated Gas Venting and Flaring		41,000
Misc Equipment Leaks	Equipment Leak Surveys	34,000
Reciprocating Compressors	Reciprocating Compressors - Leaks	33,000
Well Compl. and Work. with HF		11,000
Centrifugal Compressors	Dry Seal Centrifugal Compressors - Leaks	8,700
Transmission Tanks		7,000
Centrifugal Compressors	Wet Seal Centrifugal Compressors - Leaks	5,200
Gas Well Compl. and Work. without HF		870
Well Testing		7.3

Reporting requirements vary by segment and other facility characteristics. The base year emissions information is based on data reported for reporting year 2021 (RY 2021). For many sources, EPA has proposed revisions to reporting that may significantly change methane reported to Subpart W. Because the most recent data available is from RY 2021, this baseline uses emissions methods and factors in place in 2021. The emissions calculation methods in Subpart W can be grouped into categories: (1) direct emissions measurement; (2) combination of measurement and engineering calculations; (3) engineering calculations; (4) leak detection and use of a leaker emission factor; and (5) population count and population emission factors. Subpart W emission factors (both population and leaker emission factors) include both those developed from published empirical data and those developed from site-specific data collected by the reporting facility. Currently, the majority of emissions reported are quantified based upon population emission factors or engineering calculations, which typically include specified measurements of process operating parameters (*e.g.*, temperature or pressure). The proposed revisions to Subpart W include new measurement-based calculation methodologies for several sources, including pneumatic devices and pumps, equipment leaks, and compressors.

Calculating WEC obligations requires information on the throughput of each facility in addition to emissions information. All Subpart W facilities report information on natural gas and/or liquids throughput. However, RY2021 throughput for facilities in the natural gas processing and transmission compression segments is classified as confidential business information (CBI). For this reason, the RIA analysis uses proxy estimates to substitute for reported throughput information for facilities in these segments. The proxy throughput estimates for RY2021 were constructed by allocating total throughput for all Subpart W facilities in processing and transmission compression among the reporting facilities in proportion to carbon dioxide emissions from combustion reported by these facilities to Subpart A.

3.1.2 Baseline Projection Trends

Emissions by segment and source trends are projected by segment and source including anticipated impacts of the Oil and Gas NSPS OOOOb/EG OOOOc. Projections by segment, source (e.g., fugitives, pneumatic controllers, compressors), and unit type (e.g., centrifugal compressors) were extracted from the projections from the 2023 NSPS OOOOb/EG OOOOc RIA[10]. For emissions sources reported to GHGRP Subpart W, but not within the scope of the NSPS OOOOb/EG OOOOc projections, simplified assumptions based on projected natural gas production activity were used to project future reported emissions from those sources. The 2023 Annual Energy Outlook projects crude oil and lease condensate production to grow by 13 percent from 2022 to 2030 (24.6 to 27.7 quads) and for dry natural gas production to increase 2 percent from 2022 to 2030 (37.8 to 38.4 quads). In addition to emissions trends for affected sources and equipment types, the NSPS OOOOb/EG OOOOc RIA projections are used to break out the baseline emissions by control status, vintage, and site. These categorizations are useful for characterizing mitigation potential and control costs. Projected throughput was also estimated using the 2023 Annual Energy Outlook projection of natural gas production, applied to the base

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[10] https://www.epa.gov/system/files/documents/2023-12/eo12866_oil-and-gas-nsps-eg-climate-review-2060-av16-ria-20231130.pdf

year facility throughput (which is either as reported, or a proxy estimate depending on the segment).

Application of the emissions trends and characteristics from the NSPS OOOOb/EG OOOOc RIA projections implicitly assumes that the emissions trends among the subset of oil and gas operations reporting to the GHGRP Subpart W and potentially subject to the WEC are comparable to the trends for the overall oil and gas industry, which is subject to the NSPS OOOOb/EG OOOOc.[11] Reporters to the GHGRP represent companies with larger operations than non-reporters. However, given the various uncertainties involved in constructing the emissions projections, and the significant coverage of GHGRP of the oil and gas industry, it is reasonable to assume that the overall projections from the NSPS OOOOb/EG OOOOc are relatively representative of the trends that could be expected from GHGRP reporters potentially subject to the WEC.

3.1.3 Summary of Projections Methodology from NSPS OOOOb/EG OOOOc RIA

Because the emissions baseline incorporates trends from the Final NSPS OOOOb/EG OOOOc RIA projections, a summary of the projection methodology used in that analysis is included here. The Final RIA includes further details on the projections methodology.

The Final NSPS OOOOb/EG OOOOc RIA includes projections of activity data and emissions for the following sources: fugitive emissions/equipment leaks, pneumatic pumps, pneumatic controllers, reciprocating compressors, centrifugal compressors, liquids unloading, and storage vessels. Depending upon the source, the NSPS OOOOb/EG OOOOc includes requirements for equipment located at well sites and centralized production facilities, gathering and boosting stations, natural gas processing plants, and transmission and storage compressor stations. Tables 2-1 and 2-2 in the Final NSPS OOOOb/EG OOOOc RIA summarize the proposed requirements of those rules. The Final NSPS OOOOb/EG OOOOc RIA did not quantify regulatory impacts of the super-emitter response program.

The NSPS OOOOb/EG OOOOc activity data projections rely on historical data from the GHGI, industry data collected by EPA through an information collection request, information on

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[11] For more information on historical petroleum and natural gas systems emission trends see: https://www.epa.gov/system/files/documents/2023-10/subpart_w_2022_sector_profile.pdf

wells and oil and gas production from the firm Enverus, and projections from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO)[12,13,14]. The projections construct projected counts of oil and natural gas sites, such as well sites, compressor stations, and processing plants, that contain or are themselves affected facilities. The Final RIA contains descriptions of how projections for each site and equipment type are constructed. The projections used assumed retirement rates and annual new site construction to track new and modified facilities (which would be subject to NSPS OOOOb requirements) and existing facilities (which would be subject to state requirements based on the emissions guidelines).

3.1.4 Baseline Emissions Results

Methane emissions reported to GHGRP Subpart W in the baseline are expected to decline significantly, in particular with respect to sources subject to requirements under the proposed NSPS OOOOb/EG OOOOc. Table 3-2 lists results for the projected methane emissions baseline. This baseline does not include the effects of the Waste Emissions Charge; the policy scenario will be compared against this baseline scenario.

Table 3-2 Projected CH_4 Emissions in Baseline

Year	CH_4 tons projected for Subpart W (excl. NG dist)
2024	2,300,000
2025	2,300,000
2026	2,200,000
2027	2,200,000
2028	800,000
2029	810,000
2030	810,000
2031	810,000
2032	810,000
2033	810,000
2034	810,000
2035	820,000

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[12] Annual Energy Outlook 2023, https://www.eia.gov/outlooks/aeo/.

[13] U.S. Greenhouse Gas Emissions and Sinks, https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf

[14] Enverus Energy Analytics, http://www.enverus.com.

4 WEC SCENARIO

4.1 Identification of Regulated Sources

As described in section 2.2, CAA section 136(c) states that a WEC will be levied on applicable waste emissions above the threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent (tCO_2e) of greenhouse gases emitted per year pursuant to subpart W of part 98 of title 40.

4.1.1 Description of Applicability Standards

Owners and operators would first determine whether their facility is a WEC applicable facility and then would determine whether the facility's methane emissions exceed the applicable waste emissions threshold. To calculate the amount by which a WEC applicable facility is below or exceeding the waste emissions threshold and thus determine the amount of waste emissions charge owed, the EPA is proposing that the facility waste emissions threshold would be subtracted from facility total methane emissions, as described in the proposed regulatory text. This results in a value of metric tons of methane, referred to as the total facility applicable emissions, that is negative for facilities below the waste emissions threshold and positive for facilities exceeding the waste emissions threshold.

For a facility that would be subject to charge (*i.e.*, that has a positive value of total facility applicable emissions), there are three exemptions that may lower the facility's WEC or exempt the facility entirely from the charge. The first exemption, found in CAA section 136(f)(5), exempts from the charge emissions occurring at facilities in the onshore or offshore production segments that are caused by eligible delays in environmental permitting of gathering or transmission infrastructure. The second exemption, found in CAA section 136(f)(6), exempts from the charge facilities subject to and in compliance with the NSPS OOOOb and EG OOOOc if certain conditions are met. The third exemption, found in CAA section 136(f)(7), exempts from the charge reporting-year emission from wells that are permanently shut in and plugged. Based upon the applicability of these exemptions, the total facility applicable emissions are adjusted. The resulting value, also in units of metric tons of methane, is referred to as the WEC applicable emissions.

When determining the total WEC applicable emissions for a WEC obligated party, CAA section 136(f)(4) allows for the netting of emissions at facilities under common ownership or control within and across all applicable segments identified in 136(d). Thus, for the proposed WEC regulations, the EPA is proposing to sum the WEC applicable emissions (positive or negative) from all WEC applicable facilities under the common ownership or control of a WEC obligated party to calculate net emissions for that WEC obligated party. To determine the WEC obligated party's total annual waste emissions charge, or WEC obligation, the EPA is proposing to multiply its net metric tons of methane exceeding the waste emissions thresholds by the annual $/metric ton charge. Any WEC obligated party with net WEC emissions greater than zero would therefore have a WEC obligation and be required to pay a waste emissions charge.

4.1.2 Identification of Applicable Facilities

As an illustration of the application of these proposed terms and concepts, Table 4-1 shows the number of total facilities reporting under subpart W in RY 2021, the number of WEC applicable facilities based on RY 2021 reported data, and the number of facilities with WEC applicable emissions greater than zero based on RY 2021 emissions and throughputs, by subpart W industry segment. For this analysis, we used GHGRP data frozen as of August 13, 2022 (available through EPA's Envirofacts website[15]). To estimate the number of WEC applicable facilities within the GHGRP, we reviewed RY 2021 GHG emissions to determine which subpart W facilities reported more than 25,000 mt CO_2e. For each WEC applicable facility, we calculated the waste emissions threshold using the RY 2021 facility-level throughputs and the provisions of CAA section 136(f) appropriate for that industry segment, and then we subtracted the waste emissions threshold from the RY 2021 reported CH_4 emissions to determine whether the WEC applicable emissions for each facility were greater than zero (*i.e.*, positive). To account for netting among facilities under common ownership or control, for an owner or operator having facilities with both positive and negative WEC applicable emissions, negative WEC applicable emissions were proportionally applied to facilities with positive WEC applicable emissions to calculate emissions subject to WEC after netting. In practice, this approach only changes the

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[15] https://enviro.epa.gov/

count of facilities with emissions subject to WEC in cases where total WEC applicable emissions for an owner or operator are below zero.

Table 4-1 Numbers of Subpart W Reporting Facilities, WEC Appliable Facilities, and Facilities with WEC Applicable Emissions Greater than Zero By Industry Segment (RY 2021)

Industry Segment	Total Number of Facilities Reporting	Number of WEC Applicable Facilities	Number of Facilities with WEC Applicable Emissions >0[a]	Number of Facilities with Emissions Subject to WEC, After Netting
Onshore petroleum and natural gas production	470	408	269	258
Offshore petroleum and natural gas production	132	16	11	10
Onshore petroleum and natural gas gathering and boosting	365	327	209	176
Onshore natural gas processing	452	165	~ 50	~37
Onshore natural gas transmission compression	654	13	~ 3	~ 2
Onshore natural gas transmission pipeline	50	25	0	0
Underground natural gas storage	49	2	2	1
Liquefied natural gas storage	5	0	0	0
Liquefied natural gas import and export equipment	11	5	0	0
Total	2,188	961	~ 544	~ 484

[a] Note that the count of facilities with positive WEC applicable emissions is not shown as an exact value for the Natural Gas Processing and Onshore Natural Gas Transmission Compression industry segments due to the sensitivity of throughputs in that industry segment and the relatively low number of WEC applicable facilities. For facilities in these segments, WEC calculations used proxy estimates of throughput to avoid using sensitive data.

4.1.3 Methodology for Projecting WEC-Applicable Emissions

To estimate potential impacts of the proposed rule, the EPA projected WEC applicable facilities and WEC applicable emissions before accounting for potential emissions reductions from methane mitigation actions.

- **Identify WEC applicable facilities**. WEC applicable facilities are GHGRP facilities that report more than 25,000 metric tons CO_2e to GHGRP Subpart W and report emissions under any of the nine oil and natural gas industry segments subject to the WEC (all segments except the natural gas distribution segment). Facilities projected to report less than 25,000 metric tons CO_2e to Subpart W in a given year would not be considered subject to the WEC and are not included in projections of WEC-applicable emissions. Emissions of CO_2 and N_2O reported to Subpart W were assumed to be fixed for each facility at the same level as reported in RY 2021. Methane emissions were projected by segment and source as described in the baseline section.

- **Calculate facility waste emissions threshold from segment-specific methane intensity thresholds**. To calculate a facility's projected waste emissions threshold, the facility's projected natural gas throughput was first multiplied by the appropriate segment-specific methane intensity threshold to calculate the volume of gas equivalent to the segment-specific methane intensity threshold. These values were converted to metric tons by multiplying by the density of methane (0.0192 mt / Mscf) to calculate the waste emissions threshold in metric tons of methane The segment-specific methane intensity thresholds for each segment are listed in Table 2-1.
- **Calculate facility tons above or below waste emissions threshold, or total facility applicable emissions.** The facility's projected waste emissions threshold was subtracted from the facility's projected methane emissions to determine the total facility applicable emissions. A negative value represented the metric tons of methane emissions a facility was below the waste emissions threshold while a positive value represented the metric tons of methane emissions at the facility that exceeded the segment-specific methane intensity threshold. Facilities with projected subpart W emissions below 25,000 metric tons CO_2e were not considered eligible for the purpose of netting and positive or negative tons from these facilities were excluded.
- **Apply regulatory compliance exemption**. For this analysis, EPA assumed that the regulatory compliance exemption would apply starting in 2027 for all facilities reporting to segments containing facilities subject to the NSPS OOOOb/EG OOOOc and that had positive total facility applicable emissions. These segments are onshore production, natural gas gathering and boosting, natural gas processing, natural gas transmission compression, and underground natural gas storage segments. For this analysis, all facilities in these segments were assumed to have zero violations or deviations related to NSPS OOOOb/EG OOOOc requirements, and thus receive a regulatory compliance exemption. The assumption that the regulatory compliance exemption would apply starting in 2027 is based on prompt implementation of the schedule for state plans outlined in the final Oil and Gas EG OOOOc. Under the EG OOOOc, states have 24 months to submit their state implementation plans, and EPA must approve or deny state plans within 12 months, which means that the regulatory exemption could be available as early as January 2027, assuming no Federal Implementation Plan is needed.
- **Emissions associated with plugged well and unreasonable delay exemptions.** To calculate WEC applicable emissions, emissions associated with wells plugged in the previous year and unreasonable delay in environmental permitting are subtracted from total facility applicable methane emissions for the purpose of WEC. This analysis does not include any estimate of projected facilities or emissions that would receive these exemptions.
- **Calculate WEC applicable emissions**. For facilities with a regulatory compliance exemption, the facility's WEC applicable emission are zero. For all others, the facility's WEC applicable emissions are equal to the previously calculated total facility applicable emissions.
- **Calculate net WEC emissions by owner-operator**. For WEC Obligated Parties with common ownership or control of multiple facilities, facility tons above or below the waste emissions thresholds were summed across all facilities to calculate net tons.
- **Calculate potential WEC obligations**. WEC Obligated Parties with net tons methane of zero or below would not be subject to the WEC and have zero WEC obligations. For WEC Obligated Parties with net tons methane greater than zero, net tons were multiplied by the

WEC. In 2024 the WEC is $900/ton, in 2025 it is $1200/ton, and in 2026 and later years, it is $1500/ton of methane.

It is important to note that the reporting threshold of 25,000 mt CO_2e per facility for the GHGRP is not necessarily the same as the WEC applicable facility threshold in CAA section 136(c). Three of the industry segments included in CAA section 136(c), Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline, have a unique definition of facility in 40 CFR 98.238, and facilities in those segments only report emissions as direct emitters under subpart W, so the emissions compared to each of those thresholds would be the same for each facility. However, facilities in the other six segments report emissions under other GHGRP subparts as well (e.g., 40 CFR part 98, subpart C, General Stationary Fuel Combustion Sources). While emissions reported under these other subparts are included when an owner or operator is considering whether their facility is required to report to the GHGRP, the emissions from subparts other than subpart W would not be included when an owner or operator is determining whether their facility is a “WEC applicable facility.”

Table 4-2 shows how only a portion of the emissions that report under Subpart W are subject to the WEC. It is important to distinguish how each of these subcategories relates to the overall baseline. As shown in Table 4-1, many facilities have emissions that are below the waste emission threshold, as defined in the CAA. For those facilities whose emissions per unit of throughput are below their waste emission threshold, they do not have “WEC applicable emissions >0” (column b in Table 4-2).

Additionally, total emissions from facilities with WEC-applicable emissions greater than zero are distinct from methane tons subject to the WEC. For example, a particular facility might report total methane of 1,000 tons, but the tons of emissions that are above the waste emissions threshold could be 50 tons. Therefore, the methane tons subject to the WEC at the facility level (column c in Table 4-2), is a subset of total emissions reported under Subpart W. Lastly, the tons of methane subject to the WEC after accounting for netting at the owner-operator level (column d in Table 4-2) is a subset of WEC-applicable emissions at the facility level.[16] Based on EPA’s

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[16] Calculations of netting are based on facility characteristics in the RY 2021 base year, combined with projected changes as described in Section 3, and the WEC and netting calculations described in this section. The netting

initial analysis of the 2021 data, a significant percentage of facilities are relatively efficient and have emission rates below the Congressionally mandated thresholds. Therefore, it is reasonable to expect netting to have a notable impact on WEC-subject emissions when facilities under common ownership and control are allowed to net their emissions. Both net WEC emissions and emissions from facilities with WEC-applicable emissions greater than zero are important inputs to further analyses in this RIA.

Table 4-2 Projected CH_4 Subject to Waste Emissions Charge in Baseline Before Accounting for Mitigation and Market Responses

Year	CH_4 tons projected for Subpart W (excl. NG dist) (a)	CH_4 tons from facilities with WEC applicable emissions >0[a,b] (b)	CH_4 tons exceeding facility waste emissions thresholds[a,b] (c)	Net emissions (tons) subject to the WEC (d)
2024	2,300,000	1,600,000	1,100,000	980,000
2025	2,300,000	1,500,000	1,100,000	940,000
2026	2,200,000	1,500,000	1,000,000	900,000
2027	2,200,000	17,000	14,000	13,000
2028	800,000	17,000	14,000	13,000
2029	810,000	17,000	14,000	13,000
2030	810,000	17,000	14,000	13,000
2031	810,000	17,000	14,000	13,000
2032	810,000	17,000	14,000	13,000
2033	810,000	17,000	14,000	13,000
2034	810,000	17,000	14,000	13,000
2035	820,000	17,000	14,000	13,000

Notes:

[a] Estimates of emissions subject to the WEC in this table are based on emissions in the baseline scenario. They do not include CH_4 reductions from application of mitigation technologies or energy market responses.

[b] Emissions from WEC-applicable facilities are greater than facility emissions exceeding waste emissions thresholds because a portion of the emissions reported by a WEC-applicable facility are below the waste emissions threshold. Total emissions from WEC-applicable facilities are included because these reflect emissions potentially targeted for methane mitigation.

Projected estimates of CH4 tons subject to the WEC in the baseline reflect projections starting from emissions reported to GHGRP Subpart W for RY 2021, and thus assume this distribution of facilities and emissions.

The projections assume that starting in 2027, facilities in onshore production, gathering and boosting, transmission compression, and natural gas storage are exempted from the WEC as a result of the regulatory compliance exemption.

Table 4-3, Table 4-4, and Table 4-5 present snapshots of projected methane emissions subject to the WEC in the baseline by segment in 2024, 2026, and 2030. These results do not include mitigation or energy market responses to the WEC.

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calculations assume that patterns of WEC facility emissions and ownership are reflective of those in the 2021 GHGRP data but do not attempt to project future changes in the oil and natural gas industry.

Table 4-3 **Projected CH_4 Subject to Waste Emissions Charge in Baseline Before Accounting for Mitigation and Market Responses, by Segment, 2024, thousand tons**

Industry Segment	CH_4 projected for Subpart W (excl. NG dist)	CH_4 from facilities with WEC applicable emissions >0	Facility CH_4 exceeding waste emissions threshold	Net CH_4 subject to WEC
Onshore Production	1,300	1,000	700	650
Offshore Production	47	17	14	13
Gathering and Boosting	620	500	350	270
Natural Gas Processing	110	59	43	37
Natural Gas Transmission Compression	130	4	3	2
Natural Gas Transmission Pipeline	110	0	0	0
Underground Natural Gas Storage	13	4	2	1
LNG Import/Export	3	0	0	0
LNG Storage	0	0	0	0
Total	2,300	1,600	1,100	980

Table 4-4 **Projected CH_4 Subject to Waste Emissions Charge in Baseline Before Accounting for Mitigation and Market Responses, by Segment, 2026, thousand tons**

Industry Segment	CH4 projected for Subpart W (excl. NG dist)	CH4 from facilities with WEC applicable emissions >0	Facility CH4 exceeding waste emissions threshold	Net CH4 subject to WEC
Onshore Production	1,200	930	630	580
Offshore Production	47	17	14	13
Gathering and Boosting	620	500	350	270
Natural Gas Processing	110	58	43	37
Natural Gas Transmission Compression	130	4	3	2
Natural Gas Transmission Pipeline	110	0	0	0
Underground Natural Gas Storage	12	4	1	1
LNG Import/Export	3	0	0	0
LNG Storage	0	0	0	0
Total	2,200	1,500	1,000	900

Table 4-5 Projected CH_4 Subject to Waste Emissions Charge in Baseline Before Accounting for Mitigation and Market Responses, by Segment, 2030, thousand tons

Industry Segment	CH_4 projected for Subpart W (excl. NG dist)	CH_4 from facilities with WEC applicable emissions >0	Facility CH_4 exceeding waste emissions threshold	Net CH_4 subject to WEC
Onshore Production	230	0	0	0
Offshore Production	47	17	14	13
Gathering and Boosting	270	0	0	0
Natural Gas Processing	74	0	0	0
Natural Gas Transmission Compression	73	0	0	0
Natural Gas Transmission Pipeline	110	0	0	0
Underground Natural Gas Storage	2	0	0	0
LNG Import/Export	3	0	0	0
LNG Storage	0	0	0	0
Total	810	17	14	13

5 COST AND EMISSIONS IMPACTS

This section describes cost and emissions impacts of the WEC that arise through two pathways: 1) through the application of cost-effective methane mitigation technologies, and 2) through changes in oil and natural gas production and prices resulting from the WEC and associated mitigation responses. Section 5.1 describes the methods for estimating the expected cost of methane mitigation. Section 5.2 evaluates the equilibrium impact of increased production costs borne by oil and natural gas firms on market prices and quantities. In addition, the social cost of these energy market effects is estimated as the loss in consumer and producer surplus resulting from the WEC. Section 5.3 summarizes the expected total methane abatement and co-abatement of VOC and HAP. Lastly, WEC obligations are estimated after accounting for methane mitigation and energy market responses.

5.1 Costs of Methane Mitigation

Mitigation options were used to estimate marginal abatement cost curves (MACCs) in a reduced form marginal abatement cost (MAC) model for the WEC applicable subsegments of the Oil and Gas Industry in a manner similar to that presented in the EPA's Global Non-CO_2 Greenhouse Gas Emission Projections & Mitigation, 2015–2050 report (U.S. EPA, 2019).[17] This analysis builds from the 2019 report and includes updated baseline projections, mitigation option performance characteristics, and implementation cost assumptions. Section 3 provides more detail on the baseline projections developed for this analysis. See Appendix C, for additional details on mitigation options and costs used in this analysis. The marginal abatement cost curve (MACC) shows the cumulative mitigation potential at incrementally higher costs, where mitigation is expressed in thousand metric tons of methane, and the costs are expressed in dollars per metric ton of methane reduced. The MACC represents the aggregation of information on a wide range of mitigation technologies applied to different types of oil and natural gas operations. When evaluated against the WEC implementation schedule, we can calculate the cost of abatement resulting from facilities implementing mitigation technologies where the cost of mitigation is economic relative to the alterative WEC payment.

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[17] MAC curves are constructed by estimating the "break-even" price at which the present-value benefits and costs for each mitigation option equilibrate. The methodology produces a curve where each point reflects the average price and reduction potential if a mitigation technology were applied across the sector.

Each step of the MACC represents a calculation for a particular mitigation option applied to a specific type of activity, facility, or type of equipment annual methane emissions representing the baseline projection of emissions from facilities with WEC-applicable emissions greater than zero. Each breakeven calculation results in a cost per ton of emissions reduction (the vertical dimension of the curve) and methane mitigation potential (the horizontal dimension). The asymptotic limit of the MACC curve represents the mitigation quantity that is technically achievable[18] using mitigation technologies included in the MACC model at facilities with emissions above the facility-specific waste emissions threshold.

Mitigation technologies used in this analysis were updated based on information gathered as part of technology assessment for the recent Oil and Gas NSPS OOOOb/EG OOOOc analysis (U.S. EPA, 2021b, 2022b). Available mitigation data for the offshore segment is limited and therefore cost estimates in those segments could be overstated. We are requesting comment on the application of cost effective technologies for the offshore segment (and other segments not eligible for the regulatory compliance exemption). The mitigation technologies are characterized based on the expected lifetime of equipment, the emissions reduction efficiency, and the costs of implementation. Costs include the initial capital costs of implementation, the annual operation and maintenance costs as well as any sources of expected cost savings associated with the methane emission reductions.

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[18] The suite of mitigation measures considered for this analysis reflect the current achievable or demonstrated technologies considered in NSPS/EG analysis of the Oil and Gas Industry. The MACC model was updated for this analysis to include currently available information on mitigation measures and costs. However, the MACC model does not yet include newer emerging technologies such as remote monitoring of fugitive emissions. See Appendix C for more information on included mitigation measures.

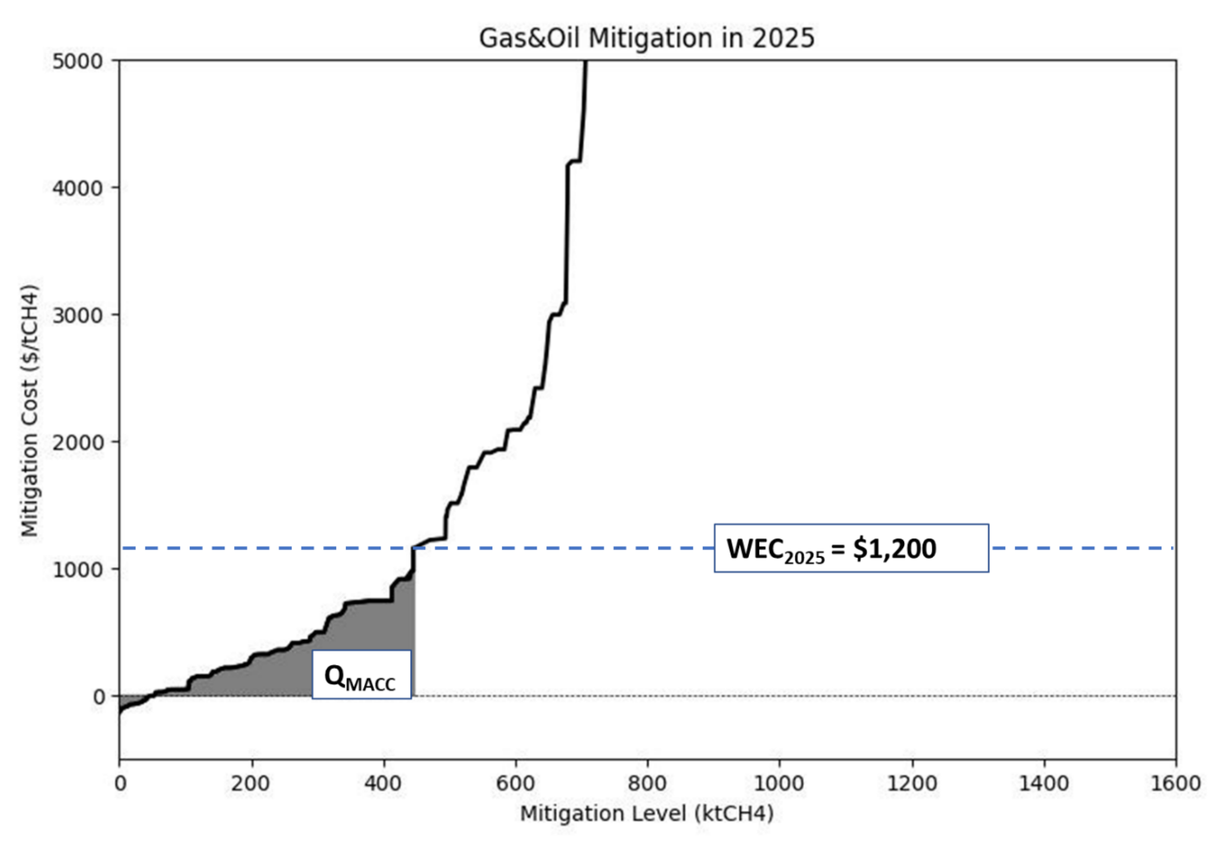

Figure 5-1 Oil and Natural Gas MACC with WEC Payment Cost in 2025

In Figure 5-1, the intersection point of the MACC and the horizontal blue line (representing the WEC payment cost of $1,200 per ton of methane for 2025) is the maximum mitigation which can be implemented at a lower cost per ton of methane abatement than the WEC. These cost-effective mitigation technologies (where cost-effective is taken to be those technologies with cost less than or equal to the WEC), shown as the total area under the MACC curve shaded in grey, is the total bottom-up engineering costs of implementing these mitigation technologies. Additional mitigation is technically feasible at higher prices ($/tCH$_4$) but would not be cost effective relative to the WEC price in 2025. As a result, facilities facing more expensive mitigation costs would elect to pay the WEC costs rather than implement these more expensive mitigation measures.

In order to account for practical limitations in the speed of deploying cost-effective mitigation to oil and gas operations, the analysis assumed a three-year phase-in period for reductions over 2024 to 2026. The phase-in parameter constrains the mitigation potential in 2024 and 2025 to 33% and 67% of total mitigation potential to simulate the assumption that it will take facilities several years to fully implement mitigation measures. Depending upon a variety of factors, potential technology deployment speed may be faster or slower than this assumption. Oil and natural gas companies have been aware of the WEC since the passage of the IRA in 2022. In addition, the NSPS OOOOb/EG OOOOc rulemaking was first proposed in 2021 and there is significant overlap in the mitigation technologies which would be used to satisfy NSPS OOOOb and EG OOOOc requirements and those which may be adopted to avoid WEC payments. However, widespread deployment of mitigation technologies may be affected by supply chain, labor, or other constraints that could prevent full utilization in the short term.

Table 5-1 presents the total cost of methane mitigation for each year, as calculated by applying the MACC representing methane mitigation options to the baseline projection in each year (2024 to 2035). The total mitigation costs over the analysis timeline are then presented in 2023 present values. The year-by-year variation in mitigation costs reflects several factors. Between 2024 and subsequent years, costs associated with mitigation rise as technology deployment increases. In addition, as the WEC rises in 2025 and 2026, additional mitigation becomes cost-effective. Then, as emissions decline in the baseline as a result of NSPS OOOOb/EG OOOOc implementation, costs associated with mitigation resulting from the WEC decline. Costs associated with NSPS OOOOb/EG OOOOc implementation are considered in the RIA for that action and are not included in this RIA to avoid double-counting. When the regulatory compliance exemption takes effect, costs (and emissions reductions) resulting from the WEC decline further.

Table 5-1 Mitigation Costs

	Year	Mitigation costs (million 2019$)
	2024	51
	2025	110
	2026	210
	2027	0.1
	2028	0.1
	2029	0.1
	2030	0.1
	2031	0.1
	2032	0.0
	2033	0.0
	2034	0.0
	2035	0.0
NPV	3%	$350
	7%	$320
EAV	3%	$38
	7%	$42

Total costs associated with methane mitigation activities include capital costs, recurring costs, and revenue from avoided losses of natural gas. Table 5-2 presents details of the composition of mitigation costs among these components including total costs with and without including revenue from avoided natural gas losses.

Table 5-2 Mitigation Cost Details (million 2019$)

Year	Mitigation costs with revenue	Mitigation costs without revenue	Capital costs	Recurring costs	Revenue from avoided natural gas losses
2024	$50.6	$69.1	$56.3	$11.3	$17.1
2025	$108.8	$146.2	$106.0	$36.6	$33.7
2026	$214.0	$275.6	$168.3	$102.3	$56.6
2027	$0.1	$0.9	$0.0	$0.9	$0.8
2028	$0.1	$0.9	$0.0	$0.9	$0.8
2029	$0.1	$0.9	$0.0	$0.9	$0.8
2030	$0.1	$0.9	$0.0	$0.9	$0.8
2031	$0.1	$0.9	$0.0	$0.9	$0.8
2032	$0.03	$0.9	$0.0	$0.9	$0.8
2033	$0.02	$0.9	$0.0	$0.9	$0.8

2034	$0.01	$0.9	$0.0	$0.9	$0.9
2035	$0.001	$0.9	$0.0	$0.9	$0.9

5.2 Market Modeling

This section describes estimates of energy market impacts of the WEC. EPA used a partial equilibrium model to estimate the energy market impacts of costs borne by oil and natural gas firms because of the WEC. This section presents estimates of the costs of these market impacts for inclusion in the benefit-cost analysis.

5.2.1 Model Description

The partial equilibrium model represents a single US oil and natural gas extraction sector, foreign supply and demand for crude oil and natural gas, and domestic demand for a combination of foreign and domestic sourced products, one for oil and one for gas. The model is calibrated to reference quantities and prices from the Energy Information Administration and parameterized with elasticities identified from a search of peer-reviewed literature.

US oil and gas producers supplied $187.8 billion of gas (34.5 TCF) and $280.2 billion of crude oil (4.1 billion barrels) in 2021. Table 5-3 shows the calculation for the total domestic oil and gas markets. By subtracting exports and adding imports to domestic production, we arrive at domestic supply totaling $161.8 billion in gas (30.7 TCF) and $417.2 billion in crude (6.1 billion barrels) supplies. Prices in 2021 were $5.44 per MCF of natural gas and $68.13 per barrel of crude.[19] The net present value of total abatement and WEC payments of $1.6 billion (discounted at 7%, $1.7 billion discounted at 3%) through 2035 are 0.3% (0.3% discounted at 3%) of 2021 domestic oil and gas domestic supply values.

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[19] Gas: https://www.eia.gov/dnav/ng/hist/n3035us3M.htm
Oil: https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

Table 5-3 Oil and Gas Markets Value and Quantity (2021)

Market / Product	Gas		Crude	
	$ Billion	**BCF**	**$ Billion**	**Million Barrels**
Output (Y)[20]	$ 187.8	34,518	$ 280.2	4,113
Imports (M)[21]	19.0	2,808	210.7	3,093
Exports (X)[22]	- 45.0	- 6,653	- 73.7	- 1,081
Domestic Supply	$ 161.8	30,673	$ 417.2	6,125

Production in the model includes elastic supply and demand combined with constant elasticity of substitution specifications for production of oil versus gas and demand for domestic versus foreign sources. The following eleven equations define the model, which we solve as a constrained non-linear system using the Conopt solver in GAMS:

Production: Total

$$Y = \bar{Y}\left(\frac{p_y}{(1+c_y)\bar{p}_y}\right)^{\sigma_y} \tag{1}$$

Production: Fuel

$$Y_f = \alpha_f Y\left(\frac{p_f}{(1+c_f)\,p_y}\right)^{\sigma_{FUEL}} \tag{2}$$

Supply: Imports

$$M_f = \bar{M}\left(\frac{p_f^M}{\bar{p}_f^M}\right)^{\sigma_f^M} \tag{3}$$

Demand: Total

$$D_f = \bar{D}_f\left(\frac{p_f^C}{\bar{p}_f^C}\right)^{\sigma_f^C} \tag{4}$$

Demand: Exports

$$X_f = \bar{X}_f\left(\frac{p_f}{\bar{p}_f}\right)^{\sigma_f^X} \tag{5}$$

Demand: Domestic

$$D_f^D = \beta_f\,\bar{D}_f\left(\frac{p_f^c}{p_f}\right)^{\sigma_f^A} \tag{6}$$

Demand: Imports

$$D_f^M = (1-\beta_f)\,\bar{D}_f\left(\frac{p_f^C}{p_f^M}\right)^{\sigma_f^A} \tag{7}$$

Market clearance: Domestic supply

$$Y_f - X_f - D_f^D = 0 \tag{8}$$

Market clearance: Imports

$$M_f - D_f^M = 0 \tag{9}$$

Zero profit: consumption

$$p_f^C = \left(\beta_f {p_f}^{1-\sigma_f^A} + (1-\beta_f)(p_f^M)^{1-\sigma_f^A}\right)^{\frac{1}{1-\sigma_f^A}} \tag{10}$$

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[20] Gas: https://www.eia.gov/international/data/world/natural-gas/dry-natural-gas-production
Oil: https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm

[21] Gas: https://www.eia.gov/international/data/world/natural-gas/dry-natural-gas-imports
Oil: https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbbl_a.htm

[22] Gas: https://www.eia.gov/international/data/world/natural-gas/dry-natural-gas-exports
Oil: https://www.eia.gov/dnav/pet/pet_move_exp_dc_NUS-Z00_mbbl_a.htm

Zero profit: supply $$p_y = \left(\alpha_{CRU} p_{CRU}^{1-\sigma_{FUEL}} + \alpha_{GAS} p_{GAS}^{1-\sigma_{FUEL}}\right)^{\frac{1}{1-\sigma_{FUEL}}} \tag{11}$$

Variable Definitions
$\bar{\cdot}$: Benchmark value of variable under bar
Y: Joint production of oil and gas
p_y: Unit price of joint output
σ_y: Elasticity of supply for joint oil-gas production
Y_f: Output of fuel f
c_Y: Compliance costs for oil and gas segments
p_f: Unit price of fuel f
α_f: Cost share of fuel f in total production
c_f: Compliance cost applicable to segment f only (gas only)
σ_{FUEL}: Elasticity of substitution across gas and oil output
M_f: Imports of fuel f
σ_f^M: Elasticity of import supply for fuel f
p_f^M: Import price of fuel f
D_f: Total demand for fuel f
σ_f^c: Demand elasticity for fuel f
X_f: Exports of fuel f
σ_f^X: Elasticity of demand for exports of fuel f
D_f^D: Demand for domestically produced fuel f
β_f: Cost share of domestic demand in total demand
p_f^C: Armington aggregation consumption price of fuel f
D_f^M: Demand for imports of fuel f
p_f^M: Import price of fuel f
σ_f^A: Armington elasticity of substitution among domestic and foreign sources of fuel f

Several elasticity values parameterize the partial equilibrium model. Model elasticities dictate oil and gas quantities change in response to changes in market prices. In other words, an elasticity indicates by what percent quantities will change for every percent change in prices. Elasticities are estimated in the literature by applying statistical techniques to historical price and quantity data. The PE model includes 10 elasticities each with a short-medium-term and long-term estimate: 1 for combined oil and gas production activity, 1 for the ability to substitute the mix of oil and gas production, 2 for the supply of imports (one oil, one gas), 4 for domestic and foreign (export) demand (one oil, one gas each), and 2 for the substitution of foreign and domestic sources (one oil, one gas).

We identified long and short-term elasticities from our review of the elasticity literature for oil and gas markets. The literature includes estimates of both long- and short-term elasticities, though these terms are not always explicit or well defined in the literature. The model represents a year's worth of production activity, which is generally consistent with the definitions of short- to medium-run used in the elasticity literature. For later periods in the analysis period, we use higher elasticity values closer to the long-run estimates, where the literature generally defines long-run as time periods on the order of multiple years to decades.

Table 5-4 lists the elasticates identified across supply and demand categories. Production supply elasticities in the literature were disaggregated by fuel source. Substitution elasticities for fuel competition between the supply of oil and gas were assumed zero (i.e., fixed proportions). The domestic supply and demand elasticities are for the United States and selected to be representative of aggregate demand. For example, estimates that cover elasticities from residential natural gas demand or only several states are excluded. These elasticities are a simple average of five short-term supply elasticities and three long-term supply elasticities as no supply elasticities for joint-production were identified in the literature. Import elasticities are taken from global mean supply elasticities and export demand elasticities from global mean demand elasticities. Foreign-domestic substitution elasticities were reported in the literature for oil and gas separately and had either an undefined term-length or were reported as long-term. The PE model takes the average of these values to parameterize short-term and long-term substitution. The PE model's own-price elasticity of domestic demand (consumption) is an average of five literature sources for long-term natural gas elasticities, four sources for long-term oil, seven for short-term gas, and nine for short-term oil elasticity. The literature sources are cited in the source in Table 5-4 and in the Reference section. Short-run supply and demand elasticities are small as it takes time for consumers and producers to adjust their equipment and processes in response to price changes. Longer-term elasticity estimates are generally higher as they capture the increased ability of market participants to change behavior, install new equipment, revise contract terms, and make other capital and operations adjustments in response to price changes over time. In this analysis, short-term elasticities were applied to the PE model for periods 2024-2025 while long-term elasticities were used for periods 2026-2038.

Table 5-4 PE Model Elasticity Values

	Short-Medium Term		Long Term	
	Gas	Oil	Gas	Oil
Supply				
Production: σ_y	0.02		0.44	
Substitution (oil-gas): σ_{FUEL}	0.0		0.0	
Imports (Foreign): σ_f^M	0.01	0.06	0.19	0.25
Demand				
Exports (Foreign): σ_f^X	-0.01	-0.01	-0.01	-0.26
Substitution (Dom.-For.): σ_f^A	2.80	7.30	2.80	7.30
Consumption: σ_f^C	-0.30	-0.15	-0.68	-0.47

Source: Elasticities are from: Rubaszek, Szafranek, and Uddin (2021); Newell and Prest (2019); Baumeister and Hamilton (2019); Marten and Garbaccio (2018); Labandeira et al. (2017); Ponce and Neumann (2014); Krichene (2005).

5.2.2 Market Impacts

EPA relied on a partial equilibrium simulation model of domestic oil and gas markets with foreign trade to estimate the market impacts of the WEC. The analysis of methane mitigation approach (Section 5.1) produced a national estimate of abatement costs, WEC payments, and emissions reductions over the analysis period. The market analysis conducted here indicates the scale and direction of estimated price and output changes in oil and gas markets resulting from the WEC, which support EPA's assessment of EO 13211 "Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use."

Together, costs of methane mitigation and WEC payments add to the production costs borne by oil and natural gas operators for the purpose of energy markets modeling. Over the analysis period, methane mitigation costs resulting from the WEC and WEC obligations fall as emissions reductions are required in the baseline by the NSPS OOOOb/EG OOOOc. This analysis assumes that cost-effective mitigation options are phased in over three years. Assuming faster adoption of methane mitigation actions would increase costs of methane mitigation and decrease the WEC obligations borne by oil and natural gas firms in the initial years of the analysis.

EPA's approach is to model the market implications of the production costs borne by oil and natural gas firms in aggregate as opposed to trying to capture the individual decisions of each company. However, production cost changes will affect entities in different segments of the oil and gas market leading to differential impacts on oil and gas prices. For example, oil and gas producers will face a portion of the costs that impact both crude and gas production costs while costs faced by natural gas processing facilities, which handle gas but no liquids, will directly impact only natural gas costs.

Cumulative costs borne by upstream segments are applied via the c_y term in Equation (1) as a fraction of total output. Cumulative costs borne by downstream (gas-only) segments are applied via the c_f term in Equation (2). The key outcomes of interest for this analysis are the changes in prices and quantities. These model results will be used to calculate the energy market welfare cost of reduced natural gas production and the change in emissions and WEC payments resulting from changes in output.

Table 5-5 shows the market model results with WEC and abatement costs having a negligible impact on natural gas and crude oil prices with 0.007%~0.008% in the first two years of the analysis period each year of the analysis period. Natural gas and crude oil quantity percentage impacts (not presented) are an order of magnitude -0.002%. Baseline projections for prices and quantities for production, imports, and exports are based on the Annual Energy Outlook 2023 reference case. The impact of WEC and abatement cost on natural gas production and prices is significantly smaller than their share relative to production value. For example, in 2024 the 0.1% production cost shock for the gas segment results in a 0.007% price increase. Relatively inelastic supply will lead to lower price changes, all else equal. Much of the cost falls on industry in the short run where elasticities are relatively low and consumer and producer gas quantities are relatively unresponsive to price changes. Natural gas trade is also a relatively small component of the domestic market and inelastic in the short term, meaning it displaces relatively little domestic gas production in response. Gas price and production change by 0.052% and -0.03% respectively while crude oil changes by 0.035% for price and -0.03% for production in 2026 (not presented here). Given WEC and abatement costs are close in 2024-2026, the relatively larger impact in 2026 than in 2024-2005 is due to the shift from short-term to long-term elasticity. With the larger long-term elasticity, oil/gas industry foresees the regulatory cos and have more flexibility to increase price and reduce production. Between 2027-2035, WEC and abatement costs becomes smaller, thus has negligible impact on natural gas and crude prices and quantities, at a level of no more than 0.001% and -0.001%.

Table 5-5 PE Model Outcomes

Year	Price: $/MCF			Quantity: BCF		
	Benchmark	WEC	% Change	Benchmark	WEC	% Change
2024	5.5055	5.5060	0.007%	35,038	35,038	-0.002%
2025	5.5276	5.5280	0.008%	35,214	35,213	-0.002%
2026	5.5497	5.5526	0.052%	35,390	35,379	-0.030%
2027	5.5719	5.5719	0.001%	35,567	35,566	-0.001%
2028	5.5942	5.5942	0.001%	35,744	35,744	-0.001%
2029	5.6165	5.6166	0.001%	35,923	35,923	-0.001%
2030	5.6390	5.6391	0.001%	36,103	36,103	-0.001%
2031	5.6616	5.6616	0.001%	36,283	36,283	-0.001%
2032	5.6842	5.6843	0.001%	36,465	36,464	-0.001%
2033	5.7069	5.7070	0.001%	36,647	36,647	-0.001%
2034	5.7298	5.7298	0.001%	36,830	36,830	-0.001%
2035	5.7527	5.7527	0.001%	37,014	37,014	-0.001%

Output reductions reduce natural gas emissions beyond the methane mitigation actions taken by producers. This analysis applies a sector-wide emissions factor to output changes from the emissions model to estimate this market-induced abatement and the value of WEC payments avoided as a result. These quantities modify the total abatement and WEC payments estimated in Section 5.1. Last, we estimate the market welfare (consumer and producer surplus) loss associated with the WEC charge as the change in price times the change in quantity.[23] Table 5-6 summarizes the total welfare loss resulting from implementing the WEC in the oil and gas markets, which totals $0.3 to 0.4 million in 2024-2025, $30.9 in 2026, and $0.01 in the later years of the analysis period. The NPV of welfare losses are $28.9 million at 3% to $25.8 million at 7%.

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[23] This calculation provides an approximate value for the welfare loss that differs depending on the relative value of the supply and demand elasticities.

Table 5-6 Market Welfare Losses

	Year	Market Welfare Loss $ Million
	2024	$0.28
	2025	$0.35
	2026	$30.85
	2027	$0.01
	2028	$0.01
	2029	$0.01
	2030	$0.01
	2031	$0.01
	2032	$0.01
	2033	$0.01
	2034	$0.01
	2035	$0.01
NPV	3%	$28.9
	7%	$25.8
EAV	3%	$3.1
	7%	$3.4

5.3 Emission Impacts

Estimating total methane mitigation and WEC transfer payments includes accounting for baseline emissions (Section 3), voluntary mitigation (Section 5.1), and market-induced mitigation (Section 5.2). The market-induced mitigation estimates in this analysis apply a sector-wide emissions coefficient of 186 metric tons of methane per billion cubic feet of natural gas times the change in market output. This calculation implicitly assumes that reductions in natural gas production occurs at facilities with an average emissions rate equal to the sector average.

The proposed WEC rule implements a charge for methane emissions that exceed certain thresholds. In practice, emissions from the oil and natural gas industry do not occur as pure methane, but as 'whole gas' or natural gas. Natural gas is composed of methane and certain other chemicals in quantities that vary depending on the natural gas and petroleum industry segment. Natural gas in the production and gathering and boosting segments include a higher proportion of compounds other than methane than gas in the transmission and storage segment. Volatile organic compounds (VOC) and hazardous air pollutants (HAP) emissions are released alongside methane. VOC and HAP emissions present adverse health consequences discussed in Section 6.2. This analysis relies on a prior study (Brown, 2011) of the composition of natural gas in different segments to estimate VOC and HAP abatement likely to occur alongside methane abatement. The prior study of several emissions sources across the natural gas industry estimated that for every metric to of methane emissions, 0.277 metric tons of VOCs and 0.01 tons of HAPs are emitted in the production sector and 0.028 tons of VOCs and 0.8kg of HAPs are emitted in transmission. Table 5-7 summarizes natural gas composition by weight and segment.

Table 5-7 Chemical Composition of Natural Gas by Weight by Segment

	Production	Transmission
Methane	0.695	0.908
VOC	0.193	0.0251
HAP	0.00728	0.00074

Table 5-8 summarizes the annual emissions reductions from abatement activities by pollutant associated with the proposed WEC rule between 2024 and 2035. The impacts of these pollutants accrue at different spatial scales. HAP emissions increase exposure to carcinogens and other toxic pollutants primarily near the emission source. VOC emissions are precursors to secondary formation of $PM_{2.5}$ and ozone on a broader region. Methane reductions are largest in years 2024 through 2026 as cost-effective mitigation options are phased in prior to EG OOOOc requirements taking effect. After the regulatory compliance exemption takes effect in 2027, emissions reductions resulting from the WEC decline significantly.[24] The remaining reductions associated with the WEC after 2027 relate to facilities in the offshore production segment, which is not subject to requirements under the NSPS OOOOb/EG OOOOc. For context, total reductions average about 33% of WEC-applicable emissions in the baseline before accounting for responses to the WEC. The market-induced component is a small fraction (about one one-hundredth to one one-thousandth) of total abatement.

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[24] EPA expects that the WEC would incentivize accelerated adoption of mitigation technologies required under the NSPS/EG. The cost analysis uses an annualized cost approach, such that breakeven price calculations involve both operating costs and capital costs spread over the mitigation technology lifetime. The abatement and costs characterized in this RIA only relate to the time period before those technologies would have been adopted in the baseline.

Table 5-8 Projected Annual Reductions of Methane, VOC, HAP Emissions from Economic Impacts (kt)

	Methane			VOCs			HAPs		
Year	Mitigated	Market-Induced	Total	Mitigated	Market-Induced	Total	Mitigated	Market-Induced	Total
2024	150	0.1	150	23	0.0	23	0.9	0.0	0.9
2025	300	0.1	300	45	0.0	45	1.7	0.0	1.7
2026	470	2.0	480	71	0.3	72	2.6	0.01	2.7
2027	5	0.0	5	0.7	0.0	0.7	0.03	0.0	0.03
2028	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2029	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2030	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2031	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2032	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2033	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2034	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2035	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2024	960	2.6	960	140	0.4	140	5.3	0.0	5.3

Table 5-9 presents details related to the calculation of methane reductions from mitigation using the MACC, further discussed in Appendix C. Total technical abatement potential represents all technology options represented in the model regardless of costs. Cost-effective abatement potential is limited to technology options with breakeven costs less than the WEC. Finally, a phase-in factor is used to account for practical limits in deployment of cost-effective mitigation in the short term. For additional details on the MACC calculations, see section 5.1.

Table 5-9 Methane Mitigation Potential Details

Year	Total Technical Abatement Potential (kt)	Cost-Effective Abatement Below WEC (kt)	Phase-In Factor	Abatement Incl. Phase-In (kt)
2024	884	445	0.33	148
2025	817	446	0.67	297
2026	765	473	1	473
2027	5	5	1	5
2028	5	5	1	5
2029	5	5	1	5
2030	5	5	1	5
2031	5	5	1	5

2032	5	5	1	5
2033	5	5	1	5
2034	5	5	1	5
2035	5	5	1	5

Note: See section 5.1 for details on mitigation modeling and assumptions

5.4 WEC Transfer Payments

This analysis estimates WEC-applicable methane emissions in the policy scenario as baseline WEC-applicable emissions less total methane mitigation. The mitigation comes from a combination of application of methane mitigation options and energy market changes (although the reductions from energy market impacts are quite small relative to methane mitigation). Table 5-10 presents projections of WEC-applicable emissions in the policy scenario as constructed from these components, and projected WEC payments calculated by applying the appropriate WEC amount, depending on the year. Because the WEC amounts ($900 in 2024, $1200 in 2025, and $1500 in 2026 and beyond) are nominal dollar amounts, the WEC obligations in Table 5-10 are expressed in undiscounted nominal dollars.

Table 5-10 Projected WEC Payments in the Policy Scenario, 2024-2035

Year	Net Methane Emissions Subject to WEC in Baseline (thousand metric tons)	Reductions from Methane Mitigation (thousand metric tons)	Reductions from Energy Market Impacts (thousand metric tons)	Net Methane Emissions Subject to WEC in Policy Scenario (thousand metric tons)	Charge Specified by Congress (nominal $ per metric ton)	WEC Payments in Policy Scenario (million undiscounted nominal $)
2024	980	150	0.1	830	$900	$750
2025	940	300	0.14	650	$1,200	$770
2026	900	470	2	430	$1,500	$640
2027	13	5	0.04	9	$1,500	$13
2028	13	5	0.04	9	$1,500	$13
2029	13	5	0.04	9	$1,500	$13
2030	13	5	0.04	9	$1,500	$13
2031	13	5	0.04	9	$1,500	$13
2032	13	5	0.04	9	$1,500	$13
2033	13	5	0.04	9	$1,500	$13
2034	13	5	0.04	9	$1,500	$13
2035	13	5	0.04	9	$1,500	$12
Total 2024-2035	2,900	960	2.6	2,000		$2,300

6 BENEFITS

The proposed rule is expected to reduce emissions of methane, VOC, and HAP emissions. This section reports the estimated monetized climate benefits associated with the estimated emission reductions. In addition to presenting monetized estimates of impacts from methane reductions, we also provide a qualitative discussion of potential climate, human health, and welfare impacts of emissions reductions we are unable to quantify and monetize.

The section describes the methods used to estimate the climate benefits from reductions of CH_4 emissions. This analysis uses estimates of the social cost of methane (SC-CH_4) to monetize the estimated changes in CH_4 emissions expected to occur over 2024 through 2035 for the proposed rule. In principle, SC-CH_4 includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-CH_4 therefore, reflects the societal value of reducing emissions of SC-CH_4 by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CH_4 emissions.

6.1 Climate Benefits Resulting from CH_4 Emission Reductions

We estimate the climate benefits of CH_4 emissions reductions expected from the proposed rule using estimates of the social cost of methane (SC-CH_4) that reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies of Science, Engineering, and Medicine (National Academies, 2017). The EPA published and used these estimates in the RIA for the December 2023 Final NSPS OOOOb/EG OOOOc Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review". The EPA solicited public comment on the methodology and use of these estimates in the RIA for the agency's December 2022 Supplemental Proposal NSPS OOOOb/EG OOOOc, and has conducted an external peer review of these estimates, as described further below.

The SC-CH_4 is the monetary value of the net harm to society from emitting a metric ton of CH_4 into the atmosphere in a given year, or the benefit of avoiding that increase. In principle, SC-CH_4 is a comprehensive metric that includes the value of all future climate change impacts (both negative and positive), including changes in net agricultural productivity, human health effects, property damage from increased flood risk, changes in the frequency and severity of natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-CH_4, therefore, reflects the societal value of reducing CH_4 emissions by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CH_4 emissions. In practice, data and modeling limitations restrain the ability of SC-CH_4 estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Since 2008, the EPA has used estimates of the social cost of various greenhouse gases (i.e., social cost of carbon (SC-CO_2), social cost of methane (SC-CH_4), and social cost of nitrous oxide (SC-N_2O)), collectively referred to as the "social cost of greenhouse gases" (SC-GHG), in analyses of actions that affect GHG emissions. The values used by the EPA from 2009 to 2016, and since 2021 have been consistent with those developed and recommended by the Interagency Working Group on the SC-GHG (IWG); and the values used from 2017 to 2020 were consistent with those required by E.O. 13783, which disbanded the IWG. During 2015–2017, the National Academies conducted a comprehensive review of the SC-CO_2 and issued a final report in 2017 recommending specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies, 2017). The IWG was reconstituted in 2021 and E.O. 13990 directed it to develop a comprehensive update of its SC-GHG estimates, recommendations regarding areas of decision-making to which SC-GHG should be applied, and a standardized review and updating process to ensure that the recommended estimates continue to be based on the best available economics and science going forward.

The EPA is a member of the IWG and is participating in the IWG's work under E.O. 13990. While that process continues, as noted in previous EPA RIAs, the EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward.[25] In the December 2022 Supplemental Proposal NSPS OOOOb/EG OOOOc RIA, the Agency included a sensitivity analysis of the climate benefits of the Supplemental Proposal using a new set of SC-GHG estimates that incorporates recent research addressing recommendations of the National Academies (2017) in addition to using the interim SC-GHG estimates[26] that the IWG recommended for use until updated estimates that address the National Academies' recommendations are available.

The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, which explains the methodology underlying the new set of estimates, in the December 2022 Supplemental Proposal NSPS OOOOb/EG OOOOc RIA.[27] The response to comments document can be found in the docket for that action.

To ensure that the methodological updates adopted in the technical report are consistent with economic theory and reflect the latest science, the EPA also initiated an external peer review panel to conduct a high-quality review of the technical report, completed in May 2023. See 88 FR at 26075/2 noting this peer review process. The peer reviewers commended the agency on its development of the draft update, calling it a much-needed improvement in estimating the SC-GHG and a significant step towards addressing the National Academies' recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates have been incorporated in the technical report to address peer reviewer recommendations. Complete information about the external peer review, including the peer

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[25] EPA strives to base its analyses on the best available science and economics, consistent with its responsibilities, for example, under the Information Quality Act.

[26] *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* (IWG, 2021)

[27] See https://www.epa.gov/environmental-economics/scghg for a copy of the final report and other related materials.

reviewer selection process, the final report with individual recommendations from peer reviewers, and the EPA's response to each recommendation is available on EPA's website.[28]

The remainder of this section provides an overview of the methodological updates incorporated into the SC-GHG estimates used in this RIA. A more detailed explanation of each input and the modeling process is provided in the technical report, *Supplementary Material for the RIA: EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* (U.S. EPA, 2023a).

The steps necessary to estimate the SC-GHG with a climate change integrated assessment model (IAM) can generally be grouped into four modules: socioeconomics and emissions, climate, damages, and discounting. The emissions trajectories from the socioeconomic module are used to project future temperatures in the climate module. The damage module then translates the temperature and other climate endpoints (along with the projections of socioeconomic variables) into physical impacts and associated monetized economic damages, where the damages are calculated as the amount of money the individuals experiencing the climate change impacts would be willing to pay to avoid them. To calculate the marginal effect of emissions, i.e., the SC-GHG in year t, the entire model is run twice – first as a baseline and second with an additional pulse of emissions in year t. After recalculating the temperature effects and damages expected in all years beyond t resulting from the adjusted path of emissions, the losses are discounted to a present value in the discounting module. Many sources of uncertainty in the estimation process are incorporated using Monte Carlo techniques by taking draws from probability distributions that reflect the uncertainty in parameters.

The SC-GHG estimates used by the EPA and many other federal agencies since 2009 have relied on an ensemble of three widely used IAMs: Dynamic Integrated Climate and Economy (DICE)[29]; Climate Framework for Uncertainty, Negotiation, and Distribution (FUND)[30]; and Policy Analysis of the Greenhouse Gas Effect (PAGE)[31]. In 2010, the IWG harmonized key inputs across the IAMs, but all other model features were left unchanged, relying on the model developers' best estimates and judgments. That is, the representation of

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[28] https://www.epa.gov/environmental-economics/scghg-tsd-peer-review

[29] Nordhaus, 2010

[30] Anthoff & Tol, 2013a, 2013b

[31] Hope, 2013

climate dynamics and damage functions included in the default version of each IAM as used in the published literature was retained.

The SC-GHG estimates in this RIA no longer rely on the three IAMs (i.e., DICE, FUND, and PAGE) used in previous SC-GHG estimates. Instead, EPA uses a modular approach to estimating the SC-GHG, consistent with the National Academies' 2017 near-term recommendations. That is, the methodology underlying each component, or module, of the SC-GHG estimation process is developed by drawing on the latest research and expertise from the scientific disciplines relevant to that component. Under this approach, each step in the SC-GHG estimation improves consistency with the current state of scientific knowledge, enhances transparency, and allows for more explicit representation of uncertainty.

The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future (RFF) Social Cost of Carbon Initiative (Rennert, Prest, et al., 2022). These socioeconomic projections (hereafter collectively referred to as the RFF-SPs) are an internally consistent set of probabilistic projections of population, GDP, and GHG emissions (CO_2, CH_4, and N_2O) to 2300. Based on a review of available sources of long-run projections necessary for damage calculations, the RFF-SPs stand out as being most consistent with the National Academies' recommendations. Consistent with the National Academies' recommendation, the RFF-SPs were developed using a mix of statistical and expert elicitation techniques to capture uncertainty in a single probabilistic approach, taking into account the likelihood of future emissions mitigation policies and technological developments, and provide the level of disaggregation necessary for damage calculations. Unlike other sources of projections, they provide inputs for estimation out to 2300 without further extrapolation assumptions. Conditional on the modeling conducted for the SC-GHG estimates, this time horizon is far enough in the future to capture the majority of discounted climate damages. Including damages beyond 2300 would increase the estimates of the SC-GHG. As discussed in (U.S. EPA, 2023a), the use of the RFF-SPs allows for capturing economic growth uncertainty within the discounting module.

The climate module relies on the Finite Amplitude Impulse Response (FaIR) model (IPCC, 2021b; Millar et al., 2017; Smith et al., 2018), a widely used Earth system model which captures the relationships between GHG emissions, atmospheric GHG concentrations, and global mean surface temperature. The FaIR model was originally developed by Richard Millar, Zeb Nicholls, and Myles Allen at Oxford University, as a modification of the approach used in IPCC AR5 to assess the GWP and GTP (Global Temperature Potential) of different gases. It is open source, widely used (e.g., IPCC (2018, 2021a)), and was highlighted by the (National Academies, 2017) as a model that satisfies their recommendations for a near-term update of the climate module in SC-GHG estimation. Specifically, it translates GHG emissions into mean surface temperature response and represents the current understanding of the climate and GHG cycle systems and associated uncertainties within a probabilistic framework. The SC-GHG estimates used in this RIA rely on FaIR version 1.6.2 as used by the IPCC (2021a). It provides, with high confidence, an accurate representation of the latest scientific consensus on the relationship between global emissions and global mean surface temperature, offers a code base that is fully transparent and available online, and the uncertainty capabilities in FaIR 1.6.2 have been calibrated to the most recent assessment of the IPCC (which importantly narrowed the range of likely climate sensitivities relative to prior assessments). See U.S. EPA (2023a) for more details.

The socioeconomic projections and outputs of the climate module are inputs into the damage module to estimate monetized future damages from climate change.[32] The National Academies' recommendations for the damage module, scientific literature on climate damages, updates to models that have been developed since 2010, as well as the public comments received on individual EPA rulemakings and the IWG's February 2021 TSD, have all helped to identify available sources of improved damage functions. The IWG (e.g., IWG 2010, 2016a, 2021), the National Academies (2017), comprehensive studies (e.g., Rose et al. (2014)), and public comments have all recognized that the damages functions underlying the IWG SC-GHG estimates used since 2013 (taken from DICE 2010 (Nordhaus, 2010); FUND 3.8 (Anthoff & Tol,

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[32] In addition to temperature change, two of the three damage modules used in the SC-GHG estimation require global mean sea level (GMSL) projections as an input to estimate coastal damages. Those two damage modules use different models for generating estimates of GMSL. Both are based off reduced complexity models that can use the FaIR temperature outputs as inputs to the model and generate projections of GMSL accounting for the contributions of thermal expansion and glacial and ice sheet melting based on recent scientific research. Absent clear evidence on a preferred model, the SC-GHG estimates presented in this RIA retain both methods used by the damage module developers. See U.S. EPA (2023a). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. Washington, DC: U.S. EPA for more details.

2013a, 2013b); and PAGE 2009 (Hope, 2013)) do not include all the important physical, ecological, and economic impacts of climate change. The climate change literature and the science underlying the economic damage functions have evolved, and DICE 2010, FUND 3.8, and PAGE 2009 now lag behind the most recent research.

The challenges involved with updating damage functions have been widely recognized. Functional forms and calibrations are constrained by the available literature and need to extrapolate beyond warming levels or locations studied in that literature. Research focused on understanding how these physical changes translate into economic impacts is still developing, and has received less public resources, relative to the research focused on modeling and improving our understanding of climate system dynamics and the physical impacts from climate change (Auffhammer, 2018). Even so, there has been a large increase in research on climate impacts and damages in the time since DICE 2010, FUND 3.8, and PAGE 2009 were published. Along with this growth, there continues to be variation in methodologies and scope of studies, such that care is required when synthesizing the current understanding of impacts or damages. Based on a review of available studies and approaches to damage function estimation, the EPA uses three separate damage functions to form the damage module. They are:

1. a subnational-scale, sectoral damage function (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (Carleton et al., 2022; Climate Impact Lab (CIL), 2023; Rode et al., 2021),
2. a country-scale, sectoral damage function (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert, Errickson, et al., 2022), and
3. a meta-analysis-based damage function (based on Howard and Sterner (2017)).

The damage functions in DSCIM and GIVE represent substantial improvements relative to the damage functions underlying the SC-GHG estimates used by the EPA to date and reflect the forefront of scientific understanding about how temperature change and SLR lead to monetized net (market and nonmarket) damages for several categories of climate impacts. The models' spatially explicit and impact-specific modeling of relevant processes allows for improved understanding and transparency about mechanisms through which climate impacts are occurring and how each damage component contributes to the overall results, consistent with the

National Academies' recommendations. DSCIM addresses common criticisms related to the damage functions underlying current SC-GHG estimates (e.g., Pindyck (2017)) by developing multi-sector, empirically grounded damage functions. The damage functions in the GIVE model offer a direct implementation of the National Academies' near-term recommendation to develop updated sectoral damage functions that are based on recently published work and reflective of the current state of knowledge about damages in each sector. Specifically, the National Academies noted that "[t]he literature on agriculture, mortality, coastal damages, and energy demand provide immediate opportunities to update the [models]" (National Academies 2017, p. 199), which are the four damage categories currently in GIVE. A limitation of both models is that the sectoral coverage is still limited, and even the categories that are represented are incomplete. Neither DSCIM nor GIVE yet accommodate estimation of several categories of temperature driven climate impacts (e.g., morbidity, conflict, migration, biodiversity loss) and only represent a limited subset of damages from changes in precipitation. For example, while precipitation is considered in the agriculture sectors in both DSCIM and GIVE, neither model takes into account impacts of flooding, changes in rainfall from tropical storms, and other precipitation related impacts. As another example, the coastal damage estimates in both models do not fully reflect the consequences of SLR-driven salt-water intrusion and erosion, or SLR damages to coastal tourism and recreation. Other missing elements are damages that result from other physical impacts (e.g., ocean acidification, non-temperature-related mortality such as diarrheal disease and malaria) and the many feedbacks and interactions across sectors and regions that can lead to additional damages.[33] See U.S. EPA (2023a) for more discussion of omitted damage categories and other modeling limitations. DSCIM and GIVE do account for the most commonly cited benefits associated with CO_2 emissions and climate change — CO_2 crop fertilization and declines in cold related mortality. As such, while the GIVE- and DSCIM-based results provide state-of-the-science assessments of key climate change impacts, they remain partial estimates of future climate damages resulting from incremental changes in CO_2, CH_4, and N_2O.[34]

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[33] The one exception is that the agricultural damage function in DSCIM and GIVE reflects the ways that trade can help mitigate damages arising from crop yield impacts.

[34] One advantage of the modular approach used by these models is that future research on new or alternative damage functions can be incorporated in a relatively straightforward way. DSCIM and GIVE developers have work underway on other impact categories that may be ready for consideration in future updates (e.g., morbidity and biodiversity loss).

Finally, given the still relatively narrow sectoral scope of the recently developed DSCIM and GIVE models, the damage module includes a third damage function that reflects a synthesis of the state of knowledge in other published climate damages literature. Studies that employ meta-analytic techniques offer a tractable and straightforward way to combine the results of multiple studies into a single damage function that represents the body of evidence on climate damages that pre-date CIL and RFF's research initiatives.[35] The first use of meta-analysis to combine multiple climate damage studies was done by Tol (2009) and included 14 studies. The studies in Tol (2009) served as the basis for the global damage function in DICE starting in version 2013R (Nordhaus, 2014). The damage function in the most recent published version of DICE, DICE 2016, is from an updated meta-analysis based on a rereview of existing damage studies and included 26 studies published over 1994-2013 (Nordhaus & Moffat, 2017). Howard and Sterner (2017) provide a more recent published peer-reviewed meta-analysis of existing damage studies (published through 2016) and account for additional features of the underlying studies. They address differences in measurement across studies by adjusting estimates such that the data are relative to the same base period. They also eliminate double counting by removing duplicative estimates. Howard and Sterner's final sample is drawn from 20 studies that were published through 2015. Howard and Sterner (2017) present results under several specifications, and their analysis shows that the estimates are somewhat sensitive to defensible alternative modeling choices. As discussed in detail in U.S. EPA (2023a), the damage module underlying the SC-GHG estimates in this RIA includes the damage function specification (that excludes duplicate studies) from Howard and Sterner (2017) that leads to the lowest SC-GHG estimates, all else equal.

The discounting module discounts the stream of future net climate damages to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages. Consistent with the findings of National Academies (2017), the economic literature, OMB Circular A-4's guidance for regulatory analysis, and IWG recommendations to date (IWG, 2010, 2013, 2016a, 2016b, 2021), the EPA continues to

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[35] Meta-analysis is a statistical method of pooling data and/or results from a set of comparable studies of a problem. Pooling in this way provides a larger sample size for evaluation and allows for a stronger conclusion than can be provided by any single study. Meta-analysis yields a quantitative summary of the combined results and current state of the literature.

conclude that the consumption rate of interest is the theoretically appropriate discount rate to discount the future benefits of reducing GHG emissions and that discount rate uncertainty should be accounted for in selecting future discount rates in this intergenerational context. OMB's Circular A-4 (2003) points out that "the analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption and to discount them at the rate consumers and savers would normally use in discounting future consumption benefits" (OMB, 2003).[36] The damage module described above calculates future net damages in terms of reduced consumption (or monetary consumption equivalents), and so an application of this guidance is to use the consumption discount rate to calculate the SC-GHG. Thus, EPA concludes that the use of the discount rate estimated using the average return on capital (7 percent in OMB Circular A-4 (2003)), which does not reflect the consumption rate, to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG.[37]

For the SC-GHG estimates used in this RIA, EPA relies on a dynamic discounting approach that more fully captures the role of uncertainty in the discount rate in a manner consistent with the other modules. Based on a review of the literature and data on consumption discount rates, the public comments received on individual EPA rulemakings, and the February 2021 TSD (IWG, 2021), and the National Academies (2017) recommendations for updating the discounting module, the SC-GHG estimates rely on discount rates that reflect more recent data on the consumption interest rate and uncertainty in future rates. Specifically, rather than using a constant discount rate, the evolution of the discount rate over time is defined following the latest empirical evidence on interest rate uncertainty and using a framework originally developed by Ramsey (1928) that connects economic growth and interest rates. The Ramsey approach explicitly reflects (1) preferences for utility in one period relative to utility in a later period and (2) the value of additional consumption as income changes. The dynamic discount rates used to develop the SC-GHG estimates applied in this RIA have been calibrated following the Newell et

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[36] Similarly, OMB's Circular A-4 (2023) points out that "The analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption before discounting them" (OMB 2023).

[37] See also the discussion of the inappropriateness of discounting consumption-equivalent measures of benefits and costs using a rate of return on capital in Circular A-4 (2023) (OMB 2023).

al. (2022) approach, as applied in Rennert, Errickson, et al. (2022); Rennert, Prest, et al. (2022). This approach uses the Ramsey (1928) discounting formula in which the parameters are calibrated such that (1) the decline in the certainty-equivalent discount rate matches the latest empirical evidence on interest rate uncertainty estimated by Bauer and Rudebusch (2020, 2023) and (2) the average of the certainty-equivalent discount rate over the first decade matches a near-term consumption rate of interest. Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates.

The resulting dynamic discount rate provides a notable improvement over the constant discount rate framework used for SC-GHG estimation in previous EPA RIAs. Specifically, it provides internal consistency within the modeling and a more complete accounting of uncertainty consistent with economic theory (Arrow et al., 2013; Cropper et al., 2014) and the National Academies' (2017) recommendation to employ a more structural, Ramsey-like approach to discounting that explicitly recognizes the relationship between economic growth and discounting uncertainty. This approach is also consistent with the National Academies (2017) recommendation to use three sets of Ramsey parameters that reflect a range of near-term certainty-equivalent discount rates and are consistent with theory and empirical evidence on consumption rate uncertainty. Finally, the value of aversion to risk associated with net damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. See U.S. EPA (2023a) for a more detailed discussion of the entire discounting module and methodology used to value risk aversion in the SC-GHG estimates.

Taken together, the methodologies adopted in this SC-GHG estimation process allow for a more holistic treatment of uncertainty than in past estimates by the EPA. The updates incorporate a quantitative consideration of uncertainty into all modules and use a Monte Carlo approach that captures the compounding uncertainties across modules. The estimation process generates nine separate distributions of discounted marginal damages per metric ton – the product of using three damage modules and three near-term target discount rates – for each gas in each emissions year. These distributions have long right tails reflecting the extensive evidence in the scientific and economic literature that shows the potential for lower-probability but higher-impact outcomes from climate change, which would be particularly harmful to society. The uncertainty grows over the modeled time horizon. Therefore, under cases with a lower near-term target discount rate – that give relatively more weight to impacts in the future – the distribution of results is wider. To produce a range of estimates that reflects the uncertainty in the estimation exercise while also providing a manageable number of estimates for policy analysis, the EPA combines the multiple lines of evidence on damage modules by averaging the results across the three damage module specifications. The full results generated from the updated methodology for methane and other greenhouse gases (SC-CO_2, SC-CH_4, and SC-N_2O) for emissions years 2020 through 2080 are provided in U.S. EPA (2023a).

Table 6-1 summarizes the resulting averaged certainty-equivalent SC-CH_4 estimates under each near-term discount rate that are used to estimate the climate benefits of the CH_4 emission reductions expected from the proposed rule. These estimates are reported in 2019 dollars but are otherwise identical to those presented in U.S. EPA (2023a). The SC-CH_4 increases over time within the models — i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2024 — because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

Table 6-1 Estimates of the Social Cost of CH_4, 2024-2035 (in 2019$ per metric ton CH_4)

	Near-Term Ramsey Discount Rate		
Year	**1.5%**	**2.0%**	**2.5%**
2024	$2,600	$1,900	$1,500
2025	$2,700	$2,000	$1,600
2026	$2,800	$2,100	$1,600
2027	$2,900	$2,200	$1,700
2028	$3,000	$2,200	$1,800
2029	$3,000	$2,300	$1,800
2030	$3,100	$2,400	$1,900
2031	$3,200	$2,500	$2,000
2032	$3,300	$2,500	$2,100
2033	$3,400	$2,600	$2,100
2034	$3,500	$2,700	$2,200
2035	$3,600	$2,800	$2,300

Source: U.S. EPA (2023a).

Note: These SC-CH_4 values are identical to those reported in the technical report U.S. EPA (2023a) adjusted for inflation to 2019 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 . The values are stated in \$/metric ton CH_4 and vary depending on the year of CH_4 emissions. This table displays the values rounded to two significant figures. The annual unrounded values used in the calculations in this RIA are available in Appendix A.5 of U.S. EPA (2023a) and at: www.epa.gov/environmental-economics/scghg.

The methodological updates described above represent a major step forward in bringing SC-GHG estimation closer to the frontier of climate science and economics and address many of the National Academies' (2017) near-term recommendations. Nevertheless, the resulting SC-GHG estimates, including the SC-CH_4 estimates presented in Table 6-1, still have several limitations, as would be expected for any modeling exercise that covers such a broad scope of scientific and economic issues across a complex global landscape. There are still many categories of climate impacts and associated damages that are only partially or not reflected yet in these estimates and sources of uncertainty that have not been fully characterized due to data and modeling limitations. For example, the modeling omits most of the consequences of changes in precipitation, damages from extreme weather events, the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions. The SC-CH_4 estimates do not account for the direct health and welfare impacts associated with tropospheric ozone produced by methane. As discussed further in U.S. EPA (2023a), recent studies have found the global ozone-related respiratory mortality benefits of CH_4 emissions reductions, which are not included in the SC-CH_4 values presented in Table 6-1, to be, in 2019 dollars, approximately $2,400 per metric ton of methane emissions in 2030 (McDuffie et al., 2023). In addition, the SC-CH_4 estimates do not reflect that methane emissions lead to a reduction in atmospheric oxidants, like hydroxyl radicals, nor do they account for impacts associated with CO_2 produced from methane oxidizing in the atmosphere. Importantly, the updated SC-GHG methodology does not yet reflect interactions and feedback effects within, and across, Earth and human systems. For example, it does not explicitly reflect potential interactions among damage categories, such as those stemming from the interdependencies of energy, water, and land use. These, and other, interactions and feedbacks were highlighted by the National Academies as an important area of future research for longer-term enhancements in the SC-GHG estimation framework.

Tables 6-2 through 6-4 present the undiscounted annual monetized climate benefits under the WEC proposal. Projected methane emissions reductions each year are multiplied by the SC-CH_4 estimate for that year. Table 6-5 shows the annual climate benefits discounted back to 2023 and the PV and the EAV for the 2024–2035 period under each discount rate. In this analysis, to calculate the present and annualized values of climate benefits, EPA uses the same discount rate as the near-term target Ramsey rate used to discount the climate benefits from future CH_4 reductions. That is, future climate benefits estimated with the SC-CH_4 at the near-term 2 percent Ramsey rate are discounted to the base year of the analysis using the same 2 percent rate.[38]

Table 6-1 Undiscounted Monetized Climate Benefits from Methane Mitigation under the WEC Proposal, 2024–2035 (millions, 2019$)

	Near-Term Ramsey Discount Rate (Annual Undiscounted)		
Year	**1.5%**	**2%**	**2.5%**
2024	$390	$290	$220
2025	$800	$590	$470
2026	$1,300	$980	$770
2027	$14	$10	$8
2028	$14	$11	$8
2029	$15	$11	$9
2030	$15	$11	$9
2031	$15	$12	$9
2032	$16	$12	$10
2033	$16	$13	$10
2034	$17	$13	$11
2035	$17	$13	$11

Note: Estimates may not sum due to independent rounding.

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using updated estimates of the SC-CH_4 from U.S. EPA (2023a).

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[38] As discussed in U.S. EPA. (2023a). *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Washington, DC: U.S. EPA, the error associated with using a constant discount rate rather than the certainty-equivalent rate path to calculate the present value of a future stream of monetized climate benefits is small for analyses with moderate time frames (e.g., 30 years or less). Ibid. also provides an illustration of the amount that climate benefits from reductions in future emissions will be underestimated by using a constant discount rate relative to the more complicated certainty-equivalent rate path.

Table 6-2 Undiscounted Monetized Climate Benefits from Partial Equilibrium Model under the WEC Proposal, 2024–2035 (millions, 2019$)

	Near-Term Ramsey Discount Rate (Annual Undiscounted) [a]		
Year	**1.5%**	**2%**	**2.5%**
2024	$0.3	$0.3	$0.2
2025	$0.4	$0.3	$0.2
2026	$5.6	$4.2	$3.3
2027	$0.1	$0.1	$0.1
2028	$0.1	$0.1	$0.1
2029	$0.1	$0.1	$0.1
2030	$0.1	$0.1	$0.1
2031	$0.1	$0.1	$0.1
2032	$0.1	$0.1	$0.1
2033	$0.1	$0.1	$0.1
2034	$0.1	$0.1	$0.1
2035	$0.1	$0.1	$0.1

Note: Estimates may not sum due to independent rounding.

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using updated estimates of the SC-CH_4 from U.S. EPA (2023a).

Table 6-3 Undiscounted Total Monetized Climate Benefits under the WEC Proposal, 2024–2035 (millions, 2019$)

	Near-Term Ramsey Discount Rate (Annual Undiscounted)[a]		
Year	**1.5%**	**2%**	**2.5%**
2024	$390	$290	$220
2025	$800	$590	$470
2026	$1,300	$990	$780
2027	$14	$10	$8
2028	$14	$11	$9
2029	$15	$11	$9
2030	$15	$11	$9
2031	$16	$12	$10
2032	$16	$12	$10
2033	$17	$13	$10
2034	$17	$13	$11
2035	$17	$14	$11

Note: Estimates may not sum due to independent rounding.

[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using updated estimates of the SC-CH_4 from U.S. EPA (2023a).

Table 6-4 Discounted Monetized Climate Benefits under the WEC Proposal, 2024–2035 (millions, 2019$)

	Discounted back to 2023[a]		
Year	**1.5%**	**2%**	**2.5%**
2024	$380	$280	$220
2025	$780	$570	$440
2026	$1,300	$930	$720
2027	$13	$10	$7
2028	$13	$10	$8
2029	$13	$10	$8
2030	$14	$10	$8
2031	$14	$10	$8
2032	$14	$10	$8
2033	$14	$10	$8
2034	$14	$11	$8
2035	$15	$11	$8
PV	$2,600	$1,900	$1,500
EAV	$230	$180	$140

Note: Estimates may not sum due to independent rounding.
[a] Climate benefits are based on changes (reductions) in CH_4 emissions and are calculated using updated estimates of the SC-CH_4 from U.S. EPA (2023a).

Unlike many environmental problems where the causes and impacts are distributed more locally, GHG emissions are a global externality making climate change a true global challenge. GHG emissions contribute to damages around the world regardless of where they are emitted. Because of the distinctive global nature of climate change, in the RIA for this proposed rule the EPA centers attention on a global measure of climate benefits from CH_4 reductions. Consistent with all IWG recommended SC-GHG estimates to date, the SC-CH_4 values presented in Table 6-1 provide a global measure of monetized damages from CH_4 emissions, and Tables 6-2 through 6-5 present the monetized global climate benefits of the CH_4 emission reductions expected from the proposed rule. This approach is the same as that taken in EPA regulatory analyses from 2009 through 2016 and since 2021. It is also consistent with guidance in OMB Circular A-4 (2003) that states when a regulation is likely to have international effects, "these effects should be reported".[39] EPA also notes that EPA's cost estimates in RIAs, including the cost estimates

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[39] While OMB Circular A-4 (2003) recommends that international effects be reported separately, the guidance also explains that "[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues." (OMB 2003). Circular A-4 (2023) states that "In certain contexts, it may be

contained in this RIA, regularly do not differentiate between the share of compliance costs expected to accrue to U.S. firms versus foreign interests, such as to foreign investors in regulated entities.[40] A global perspective on climate effects is therefore consistent with the approach EPA takes on costs. There are many reasons, as summarized in this section — and as articulated by OMB and in IWG assessments (IWG 2010, 2013, 2016a, 2016b, 2021), the 2015 Response to Comments (IWG 2015), and in detail in EPA (2023a) and in Appendix A of the Response to Comments document for the Final Oil and Gas NSPS OOOOb/EG OOOOc — why the EPA focuses on the global value of climate change impacts when analyzing policies that affect GHG emissions.

International cooperation and reciprocity are essential to successfully addressing climate change, as the global nature of greenhouse gases means that a ton of GHGs emitted in any other country harms those in the U.S. just as much as a ton emitted within the territorial U.S. Assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. This is a classic public goods problem because each country's reductions benefit everyone else, and no country can be excluded from enjoying the benefits of other countries' reductions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis — and so benefit the U.S. and its citizens and residents — is for *all* countries to base their policies on global estimates of damages. A wide range of

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particularly appropriate to include effects experienced by noncitizens residing abroad in your primary analysis. Such contexts include, for example, when:

- assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. citizens and residents that are difficult to otherwise estimate;
- assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. national interests that are not otherwise fully captured by effects experienced by particular U.S. citizens and residents (e.g., national security interests, diplomatic interests, etc.);
- regulating an externality on the basis of its global effects supports a cooperative international approach to the regulation of the externality by potentially inducing other countries to follow suit or maintain existing efforts; or
- international or domestic legal obligations require or support a global calculation of regulatory effects"

(OMB 2023).

[40] For example, in the RIA for the 2018 Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources, the EPA acknowledged that some portion of regulatory costs will likely "accru[e] to entities outside U.S. borders" through foreign ownership, employment, or consumption (EPA 2018, p. 3-13). In general, a significant share of U.S. corporate debt and equities are foreign-owned, including in the oil and gas industry.

scientific and economic experts have emphasized the issue of international cooperation and reciprocity as support for assessing global damages of GHG emission in domestic policy analysis. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to also assess global climate damages of their policies and to take steps to reduce emissions. For example, many countries and international institutions have already explicitly adapted the global SC-GHG estimates used by EPA in their domestic analyses (e.g., Canada, Israel) or developed their own estimates of global damages (e.g., Germany), and recently, there has been renewed interest by other countries to update their estimates since the draft release of the updated SC-GHG estimates presented in the December 2022 Oil and Gas Supplemental Proposal NSPS OOOOb/EG OOOOc RIA.[41] Several recent studies have empirically examined the evidence on international GHG mitigation reciprocity, through both policy diffusion and technology diffusion effects. See U.S. EPA (2023a) for more discussion.

For all of these reasons, the EPA believes that a global metric is appropriate for assessing the climate benefits of avoided methane emissions in this final RIA. In addition, as emphasized in the National Academies (2017) recommendations, “[i]t is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States.” The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to U.S. citizens and residents. The increasing interconnectedness of global economy and populations means that impacts occurring outside of U.S. borders can have significant impacts on U.S. interests. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts point to the global nature of the climate

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[41] In April 2023, the government of Canada announced the publication of an interim update to their SC-GHG guidance, recommending SC-GHG estimates identical to the EPA’s updated estimates presented in the December 2022 Supplemental Proposal RIA. The Canadian interim guidance will be used across all federal departments and agencies, with the values expected to be finalized by the end of the year. https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html.

change problem and are better captured within global measures of the social cost of greenhouse gases.

In the case of this global pollutant, for the reasons articulated in this section, the assessment of global net damages of GHG emissions allows EPA to fully disclose and contextualize the net climate benefits of the CH_4 emission reductions expected from this proposed rule. The EPA disagrees with commenters on the 2022 Supplemental NSPS OOOOb/EG OOOOc proposal who suggest that the EPA can or should use a metric focused on benefits resulting solely from changes in climate impacts occurring within U.S. borders. The global models used in the SC-GHG modeling described above do not lend themselves to be disaggregated in a way that could provide comprehensive information about the distribution of the rule's climate benefits to citizens and residents of particular countries, or population groups across the globe and within the U.S. Two of the models used to inform the damage module, the GIVE and DSCIM models, have spatial resolution that allows for some geographic disaggregation of a subset of climate impacts across the world. This permits the calculation of a partial GIVE and DSCIM-based SC-GHG measuring the damages from four or five climate impact categories (respectively) projected to physically occur within the U.S., subject to caveats. As discussed at length in U.S. EPA (2023a) these damage modules are only a partial accounting and do not capture many significant pathways through which climate change affects public health and welfare. For example, this modeling omits most of the consequences of changes in precipitation, damages from extreme weather events (e.g., wildfires), the potential for nongradual damages from passing critical thresholds (e.g., tipping elements) in natural or socioeconomic systems, and non-climate mediated effects of GHG emissions other than CO_2 fertilization (e.g., tropospheric ozone formation due to CH_4 emissions). Thus, this modeling only cover a subset of potential climate change impacts. Furthermore, the damage modules do not capture spillover or indirect effects whereby climate impacts in one country or region can affect the welfare of residents in other countries or regions — for example through the movement of refugees.

Additional modeling efforts can and have shed further light on some omitted damage categories. For example, the Framework for Evaluating Damages and Impacts (FrEDI) is an open-source modeling framework developed by the EPA to facilitate the characterization of net annual climate change impacts in numerous impact categories within the contiguous U.S. and monetize the associated distribution of modeled damages (Sarofim et al., 2021; U.S. EPA, 2021a).[42] The additional impact categories included in FrEDI reflect the availability of U.S.-specific data and research on climate change effects. As discussed in U.S. EPA (2023a), results from FrEDI show that annual damages resulting from climate change impacts within the contiguous U.S. (CONUS) (i.e., excluding Hawaii, Alaska, and U.S. territories) and for impact categories not represented in GIVE and DSCIM are expected to be substantial. For example, FrEDI estimates a partial SC-CH_4 of $590/mt$CH_4$ for damages physically occurring within CONUS for 2030 emissions (under a 2 percent near-term Ramsey discount rate) (Hartin et al., 2023), compared to a GIVE and DSCIM-based U.S.-specific SC-CH_4 of $280/mt$CH_4$ and $75/mt$CH_4$, respectively, for 2030 emissions. While the FrEDI results help to illustrate how monetized damages physically occurring within CONUS increase as more impacts are reflected in the modeling framework, they are still subject to many of the same limitations associated with the DSCIM and GIVE damage modules, including the omission or partial modeling of important damage categories.[43] Finally, none of these modeling efforts — GIVE, DSCIM, and FrEDI — reflect non-climate mediated effects of GHG emissions experienced by U.S. populations (other than CO_2 fertilization effects on agriculture). As one example of new research on non-climate mediated effects of methane emissions, McDuffie et al. (2023) estimate the monetized increase in respiratory-related human mortality risk from the ozone produced from a marginal pulse of methane emissions. Using the socioeconomics from the RFF-SPs and the 2 percent near-term

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[42] The FrEDI framework and Technical Documentation have been subject to a public review comment period and an independent external peer review, following guidance in the EPA Peer-Review Handbook for Influential Scientific Information (ISI). Information on the FrEDI peer-review is available at the EPA Science Inventory EPA Science Inventory. (2021). *Technical Documentation on The Framework for Evaluating Damages and Impacts (FrEDI)*. Retrieved February 16, 2023 from https://cfpub.epa.gov/si/si_public_record_report.cfm?dirEntryId=351316&Lab=OAP&simplesearch=0&showcriteria=2&sortby=pubDate&searchall=fredi&timstype=&datebeginpublishedpresented=02/14/2021.

[43] Another method that has produced estimates of the effect of climate change on U.S.-specific outcomes uses a top-down approach to estimate aggregate damage functions. Published research using this approach include total-economy empirical studies that econometrically estimate the relationship between GDP and a climate variable, usually temperature. As discussed in U.S. EPA. (2023a). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. Washington, DC: U.S. EPA, the modeling framework used in the existing published studies using this approach differ in important ways from the inputs underlying the SC-GHG estimates described above (e.g., discounting, risk aversion, and scenario uncertainty) and focus solely on CO_2. Hence, we do not consider this line of evidence in the analysis for this RIA. Updating the framework of total-economy empirical damage functions to be consistent with the methods described in this RIA and ibid. would require new analysis. Finally, because total-economy empirical studies estimate market impacts, they do not include non-market impacts of climate change (e.g., mortality impacts) and therefore are also only a partial estimate. The EPA will continue to review developments in the literature and explore ways to better inform the public of the full range of GHG impacts.

Ramsey discounting approach, this additional risk to U.S. populations is on the order of approximately \$320/mtCH_4 for 2030 emissions (U.S. EPA 2023a).

Taken together, applying the U.S.-specific partial SC-CH_4 estimates derived from the evidence described above to the CH_4 emissions reduction expected under the WEC proposal would yield substantial benefits. For example, the present value of the climate benefits of the proposed rule as measured by FrEDI using additional U.S.-specific data and research on climate change impacts in CONUS are estimated to be \$510 million (under a 2 percent near-term Ramsey discount rate).[44] However, even with these additional impact categories, the numerous explicitly omitted damage categories and other modeling limitations discussed above and throughout U.S. EPA (2023a) make it likely that these estimates underestimate the benefits to U.S. citizens and residents of the CH_4 reductions from the proposed rule; the limitations in developing a U.S.-specific estimate that accurately captures direct and spillover effects on U.S. citizens and residents further demonstrates that it is more appropriate to use a global measure of climate benefits from CH_4 reductions. The EPA will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of GHG impacts.

6.2 Health Effects Associated with Exposure to Non-GHG Pollutants

6.2.1 Ozone-Related Impacts Due to VOC Emissions

This proposed rulemaking is projected to reduce VOC emissions, which are a precursor to ozone. Ozone is not generally emitted directly into the atmosphere but is created when its two primary precursors, VOC and oxides of nitrogen (NO_X), react in the atmosphere in the presence of sunlight. In urban areas, compounds representing all classes of VOC can be important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2013). Recent observational and modeling

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[44] DCIM and GIVE use global damage functions. Damage functions based on only U.S.-data and research, but not for other parts of the world, were not included in those models. FrEDI does make use of some of this U.S.-specific data and research and as a result has a broader coverage of climate impact categories.

studies have found that VOC emissions from oil and natural gas operations can impact ozone levels. Emissions reductions may decrease ozone formation, human exposure to ozone, and the incidence of ozone-related health effects.

Calculating ozone impacts from changes in VOC emissions requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total due to data and resource constraints. In light of these limitations, we present an illustrative screening analysis of ozone-related health benefits in Appendix A based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this screening analysis in the estimate of benefits (and net benefits) projected from this proposal. To more definitively analyze the impacts of VOC reductions from this proposed rule on ozone health benefits, we would need credible projections of spatial patterns of expected VOC emissions reductions. Similarly, due to the high degree of variability in the responsiveness of ozone formation to VOC emissions reductions, we are unable to determine how this rule might affect air quality in downwind ozone nonattainment areas without modeling air quality changes.

6.2.1.1 Ozone Health Effects

Human exposure to ambient ozone concentrations is associated with adverse health effects, including premature respiratory mortality and cases of respiratory morbidity (U.S. EPA, 2020a). Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical, and epidemiological studies (U.S. EPA, 2020a). When adequate data and resources are available, the EPA has generally quantified several health effects associated with exposure to ozone (U.S. EPA, 2010, 2011a, U.S. EPA, 2021c). These health effects include respiratory morbidity, such as asthma attacks, hospital and emergency department visits, lost school days, and premature respiratory mortality. The scientific literature is also suggestive that exposure to ozone is associated with chronic respiratory damage and premature aging of the lungs.

6.2.1.2 Ozone Vegetation Effects

Exposure to ozone has been found to be associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2020a). Sensitivity to ozone is highly variable across species, with over 66 vegetation species identified as “ozone-sensitive,” many of which occur in state and national parks and forests. These effects include those that cause damage to, or impairment of, the intended use of the plant or ecosystem. Such effects are considered adverse to public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, changed to species composition, and changes in ecosystems and associated ecosystem services.

6.2.1.3 Ozone Climate Effects

Ozone is a well-known short-lived climate forcing GHG (U.S. EPA, 2013). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun’s harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). The IPCC AR5 estimated that the contribution to current warming levels of increased tropospheric ozone concentrations resulting from human methane, NO_X, and VOC emissions was 0.5 W/m^2, or about 30 percent as large a warming influence as elevated CO_2 concentrations. This quantifiable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

6.2.2 Ozone-Related Impacts Due to Methane

The tropospheric ozone produced by the reaction of methane in the atmosphere has harmful effects for human health and plant growth in addition to its climate effects (Nolte et al., 2018). In remote areas, methane is a dominant precursor to tropospheric ozone formation. Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane (Myhre et al., 2013). Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future (Myhre et al., 2013). Unlike NO_X and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane’s long atmospheric lifetime when compared to these other ozone precursors (Myhre et al., 2013). Reducing methane emissions, therefore, will contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects (Sarofim et al., 2015; USGCRP, 2018). The benefits of such reductions are global and occur in both urban and rural areas. As discussed in Section 6.1, these effects are not included in estimates of the social cost of methane.

6.2.3 $PM_{2.5}$-Related Impacts Due to VOC Emissions

This proposed rulemaking is expected to result in emissions reductions of VOC, which are a precursor to $PM_{2.5}$, thus decreasing human exposure to $PM_{2.5}$ and the incidence of $PM_{2.5}$-related health effects, although the magnitude of this effect has not been quantified at this time. Most VOC emitted are oxidized to CO_2 rather than to PM, but a portion of VOC emissions contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2020a). Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution (U.S. EPA, 2019a). The potential for an organic compound to partition into the particle phase is highly dependent on its volatility such that compounds with lower volatility are more prone to partition into the particle phase and form secondary organic aerosols (SOA) (Cappa & Wilson, 2012; Donahue, Kroll, Pandis, & Robinson, 2012; Jimenez et al., 2009). Hydrocarbon emissions from oil and natural gas operations tend to be dominated by high volatility, low-carbon number compounds that are less likely to form SOA (Helmig et al., 2014; Koss et al., 2017; Pétron et al., 2012). Given that only a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions, and the relatively volatile nature of VOCs emitted from this sector, it is unlikely that the VOC emissions reductions projected to occur under this proposal would have a large contribution to ambient secondary organic carbon aerosols. Therefore, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Moreover, without modeling air quality changes, we are unable to determine how this rule might affect air quality in downwind $PM_{2.5}$ nonattainment areas.

6.2.3.1 $PM_{2.5}$ Health Effects

Decreasing exposure to $PM_{2.5}$ is associated with significant human health benefits, including reductions in respiratory mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$ exposure with adverse health effects in numerous toxicological, clinical, and epidemiological studies (U.S. EPA, 2020a). These health effects include asthma development and aggravation, decreased lung function, and increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing (U.S. EPA, 2019a). These health effects result in hospital and ER visits, lost workdays, and restricted activity days. When adequate data and resources are available, the EPA has quantified the health effects associated with exposure to $PM_{2.5}$ (U.S. EPA, 2021d).

When the EPA quantifies $PM_{2.5}$-related benefits, the Agency assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2019a). Based on our review of the current body of scientific literature, the EPA estimates PM-related premature mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

6.2.3.2 PM Welfare Effects

Suspended particles and gases degrade visibility by scattering and absorbing light. Decreasing secondary formation of $PM_{2.5}$ from VOC emissions could improve visibility throughout the U.S. Visibility impairment has a direct impact on people’s enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006, 2011b, 2011c, 2012) show that visibility benefits are a significant welfare benefit category. However, without air quality modeling of $PM_{2.5}$ impacts, we are unable to estimate visibility related benefits.

Separately, persistent and bioaccumulative HAP reported as emissions from oil and natural gas operations, including polycyclic organic matter, could lead to PM welfare effects.

Several significant ecological effects are associated with the deposition of organic particles, including persistent organic pollutants and polycyclic aromatic hydrocarbons (PAHs) (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. (U.S. EPA, 2012).

6.2.4 Hazardous Air Pollutants (HAP) Impacts

Available emissions data show that several different HAP are emitted from oil and natural gas operations. The HAP emissions from the oil and natural gas sector in the 2017 National Emissions Inventory (NEI) emissions data are summarized in Table 6-6. The table includes either oil and natural gas nonpoint or oil and natural gas point emissions of at least 10 tons per year, in descending order of annual nonpoint emissions. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and natural gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011d).

Table 6-5 Top Annual HAP Emissions as Reported in 2017 NEI for Oil and Natural Gas Sources

Pollutant	Nonpoint Emissions (tons/year)	Point Emissions (tons/year)
Benzene	26,869	502
Xylenes (Mixed Isomers)	25,410	506
Formaldehyde	23,413	222
Toluene	18,054	823
Acetaldehyde	2,722	26
Hexane	2,675	886
Ethyl Benzene	2,021	113
Acrolein	1,602	18
Methanol	1,578	342
1,3-Butadiene	337	5.80E-01
2,2,4-Trimethylpentane	252	46
Naphthalene	104	1.10E+00
Propionaldehyde	102	0.00E+00
PAH/POM - Unspecified	68	2.50E-02
1,1,2-Trichloroethane	25	1.40E-03
Methylene Chloride	22	8.70E-02
1,1,2,2-Tetrachloroethane	14	1.90E-03
Ethylene Dibromide	13	1.90E-03
Methyl Tert-Butyl Ether	0	17.30

In the subsequent sections, we describe the health effects associated with the main HAP of concern from the oil and natural gas sector: benzene (Section 6.2.4.1), formaldehyde (Section 6.2.4.2), toluene (Section 6.2.4.3), carbonyl sulfide (Section 6.2.4.4), ethylbenzene (Section 6.2.4.5), mixed xylenes (Section 6.2.4.6), and n-hexane (Section 6.2.4.7), and other air toxics (Section 6.2.4.8). This proposal is projected to reduce 4,000 tons of HAP emissions over the 2023 through 2035 period. With the data available, it was not possible to estimate the change in emissions of each individual HAP.

Monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAP in this analysis. Instead, we are providing a qualitative discussion of the health effects associated with HAP emitted from sources subject to control under the proposed WEC. The EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional aspects of HAP-related risk from the oil and natural gas sector, including the distribution of that risk. This is discussed further in the context of environment justice in Section 9.3.

6.2.4.1 Benzene

The EPA's Integrated Risk Information System (IRIS) database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice (IARC, 1982; Irons, Stillman, Colagiovanni, & Henry, 1992; U.S. EPA, 2003a). The EPA states that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen, and the U.S. Department of Health and Human Services has characterized benzene as a known human carcinogen (IARC, 1987; NTP, 2004). Several adverse noncancer health effects have been associated with chronic inhalation of benzene in humans including arrested development of blood cells, anemia, leukopenia, thrombocytopenia, and aplastic anemia. Respiratory effects have been reported in humans following acute exposure to benzene vapors, such as nasal irritation, mucous membrane irritation, dyspnea, and sore throat (ATSDR, 2007a).

6.2.4.2 Formaldehyde

In 1989, the EPA classified formaldehyde as a probable human carcinogen based on limited evidence of cancer in humans and sufficient evidence in animals (U.S. EPA, 1991b). Later the IARC (2006, 2012) classified formaldehyde as a human carcinogen based upon sufficient human evidence of nasopharyngeal cancer and strong evidence for leukemia. Similarly, in 2016, the National Toxicology Program (NTP) classified formaldehyde as known to be a human carcinogen based on sufficient evidence of cancer from studies in humans supporting data on mechanisms of carcinogenesis (NTP, 2016). Formaldehyde inhalation exposure causes a range of noncancer health effects including irritation of the nose, eyes, and throat in humans and animals. Repeated exposures cause respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia in humans. Airway inflammation, including eosinophil infiltration, has been observed in animals exposed to formaldehyde. In children, there is evidence that formaldehyde may increase the risk of asthma and chronic bronchitis (ATSDR, 1999; WHO, 2002).

6.2.4.3 Toluene[45]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

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[45] All health effects language for this section came from: U.S. EPA (2005b).

6.2.4.4 Carbonyl Sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate the eyes and skin in humans (U.S. National Library of Medicine, 2020). No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under the EPA's IRIS program for evidence of human carcinogenic potential (U.S. EPA, 1991a).

6.2.4.5 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route (Maltoni et al., 1997; Maltoni, Conti, Cotti, & Belpoggi, 1985). The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP, 1999). The NTP (1999) carried out a chronic inhalation bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

6.2.4.6 Mixed Xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects (U.S. EPA, 2003b). Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys (ATSDR, 2007b). Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination (ATSDR, 2007b). The EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

6.2.4.7 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes, and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005a), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.

6.2.4.8 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by this rule, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in the EPA's IRIS database.[46]

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[46] The U.S. EPA Integrated Risk Information System (IRIS) database is available at https://www.epa.gov/iris. Accessed April 26, 2020.

7 COMPARISON OF BENEFITS AND COSTS

7.1 Comparison of Benefits and Costs

This section presents a comparison of quantified benefits and costs. Additionally, projections of WEC payments are presented separately from costs and benefits as transfers. All estimates are in 2019 dollars. All costs, emissions changes, and benefits are estimated for the years 2024 to 2035 relative to a baseline without the proposed Waste Emissions Charge. The monetized benefits presented are climate benefits calculated using the social cost of methane. The costs presented are engineering costs of methane mitigation technologies and energy market costs related to the outcomes of the partial equilibrium modeling.

Table 7-1 summarizes the emissions reductions estimated to result from the WEC over the 2024 to 2035 period. Table 7-2 presents the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 2, 3, and 7 percent, of the changes in quantified benefits, costs, and net benefits [47]. These values are discounted to 2023. Note that while the PV of the costs and net benefits are calculated with discount rates of 2 percent, 3 percent, and 7 percent, the monetized climate benefits are only discounted at 2 percent. Table 7-2 includes consideration of non-monetized benefits associated with the emissions reductions resulting from this proposal.

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[47] Monetized climate effects are presented under a 2 percent near-term Ramsey discount rate, consistent with EPA's updated estimates of the SC-GHG. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. OMB finalized an update to Circular A-4 in 2023, in which it recommended the general application of a 2.0 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC-GHG estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG. See Section 6.1 for more discussion.

Table 7-1 Projected Emissions Reductions from the Proposed Waste Emissions Charge, 2024-2035

	Emission Changes			
Proposal	**Methane (thousand metric tons)**	**VOC (thousand metric tons)**	**HAP (thousand metric tons)**	**Methane (million metric tons CO2 Eq. using GWP=28)**
Total	960	140	5	27

Table 7-2 Projected Benefits and Costs from the Proposed Waste Emissions Charge (million 2019$)

	2 Percent Near-Term Ramsey Discount Rate					
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Monetized Climate Benefits[a]	$1,900	$180	$1,900	$180	$1,900	$180
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	PV	**EAV**	**PV**	**EAV**	**PV**	**EAV**
Total Social Costs	$390	$37	$380	$38	$340	$43
Cost of Methane Mitigation	$360	$34	$350	$35	$320	$40
Cost of Energy Market Impacts	$30	$3	$29	$3	$26	$3
Net Benefits	$1,500	$140	$1,500	$140	$1,600	$140
Non-Monetized Benefits	Ozone benefits from reducing 960 thousand metric tons of methane from 2024 to 2035 PM2.5 and ozone health benefits from reducing 140 thousand metric tons of VOC from 2024 to 2035 HAP benefits from reducing 5 metric tons of HAP from 2024 to 2035 Visibility benefits Reduced vegetation effects					

[a] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Table 6-5 for the full range of monetized climate benefit estimates.

[b] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix A of the RIA.

7.2 Annual Benefits and Costs

Table 7-3 presents annual emissions reductions of methane, VOC, and HAP emissions from mitigation actions and energy market impacts. Table 7-4 provides the net benefits calculated from this rule and the corresponding present value and equivalent annualized value (EAV) discounted to the year 2023 using discount rates of 2, 3, and 7 percent.

Table 7-3 Projected Annual Emissions Reductions from the Proposed Waste Emissions Charge (thousand metric tons)

Year	Methane			VOC			HAP		
	Mitigated	Market-Induced	Total	Mitigated	Market-Induced	Total	Mitigated	Market-Induced	Total
2024	150	0.1	150	23	0.0	23	0.9	0.0	0.9
2025	300	0.1	300	45	0.0	45	1.7	0.0	1.7
2026	470	2.0	480	71	0.3	72	2.6	0.0	2.7
2027	5	0.0	5	0.7	0.0	0.7	0.03	0.0	0.03
2028	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2029	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2030	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2031	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2032	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2033	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2034	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
2035	5	0.0	5	0.5	0.0	0.5	0.0	0.0	0.0
Total	**960**	**2.6**	**960**	**140**	**0.4**	**140**	**5.3**	**0.0**	**5.3**

Table 7-4 Summary of Annual Undiscounted Values, Present Values, and Equivalent Annualized Values for the 2024–2035 Timeframe for Estimated Incremental Abatement Costs, Benefits, and Net Benefits for This Rule (millions of 2019$, discounted to 2023)

Year	***Climate Benefits***[a] ***(2% DR)***	***Total Social Costs ($MM)***			***Net Benefits (2% Benefits)***		
2024	$290	$51			$240		
2025	$590	$110			$490		
2026	$990	$240			$740		
2027	$10	$0			$10		
2028	$11	$0			$11		
2029	$11	$0			$11		
2030	$11	$0			$11		
2031	$12	$0			$12		
2032	$12	$0			$12		
2033	$13	$0			$13		
2034	$13	$0			$13		
2035	$14	$0			$14		
Discount Rate	2%	2%	3%	7%	2%[b]	3%[b]	7%[b]
PV	$1,900	$390	$380	$340	$1,500	$1,500	$1,600
EAV	$180	$37	$38	$43	$140	$140	$140

[a] Monetized climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Tables 6.2-6.5 for the full range of monetized climate benefit estimates.

[b] Headings denote what percent discount rates are used in calculating different versions of net benefits. In this case, EPA is using 2% near-term Ramsey discount rate for climate benefits and 2%, 3%, and 7% discount rates for costs respectively.

7.3 Transfer Payments

WEC payments are transfers and do not affect total net benefits to society as a whole because payments by oil and natural gas operators are offset by receipts by the government. Therefore, from a net-benefit accounting perspective, transfers are considered separately from costs and benefits (and are therefore not included in Table 7-2). As explained in Section 2.7, the approach taken here is in line with OMB guidance and the approach taken for RIAs for other rules impacting payments to the government, such as the Bureau of Land Management (BLM)'s waste prevention rule.

One of the reasons that transfers are not considered costs is because they represent payments to the U.S. Treasury that do not affect total resources available to society. Payments to the U.S. Treasury can then be used to fund other programs, and the pairing of revenue collection (e.g., the WEC payments) with commensurate expenditures (e.g., financial assistance programs) by the federal government can be designed to be revenue neutral. The Methane Emission Reduction Program created under CAA section 136 includes both collection and expenditure components. In addition to establishing the WEC, another key purpose of CAA section 136 is to encourage the development of innovative technologies in the detection and mitigation of methane emissions. See 168 Cong. Rec. E869 (August 23, 2022) (statement of Rep. Frank Pallone). CAA section 136(a) and (b) provides $1.55 billion to, among other things, help finance the early adoption of emissions reduction methodologies and technologies and to support monitoring of methane emissions. These incentives for methane mitigation and monitoring complement the WEC.

The WEC has the effect of better aligning the economic incentives of oil and natural gas companies with the costs and benefits faced by society from oil and gas activities. In the baseline scenario the environmental damages resulting from methane emissions from the oil and gas sector are a negative externality spread across society as a whole. Under the WEC, this negative externality is internalized, oil and gas companies are required to make WEC payments in proportion to the climate damages of methane emissions subject to the WEC.[48] Alternatively, firms can avoid making WEC payments by mitigating their emissions generating climate benefits associated with the amount of mitigation.

Table 7-5 provides details of the calculation steps used to estimate projected WEC obligations and climate damages based on projected emission subject to WEC. In order to compare projected WEC payments to climate damages from emissions subject to the WEC,

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[48] Note that Congress specified that the WEC would rise to $1,500 per metric ton of methane in 2026 and beyond. This value is consistent with estimates of climate damages associated with emissions of a metric ton of methane that were available at the time the IRA was passed. The February 2021, 'Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990,' estimated that the social cost of CH4 under a 3% discount rate for emissions occuring in the year 2020 was $1,500.

WEC payments are converted from nominal dollars to 2019 constant dollars using a chain-weighted GDP price index from the 2023 Annual Energy Outlook.

Table 7-5 Details of Projected WEC Obligations and Climate Damages from Emissions Subject to WEC (million 2019$)

Year	Methane Emissions Subject to WEC in Policy Scenario (thousand metric tons)	Charge Specified by Congress (nominal $ per metric ton)	WEC Payments in Policy Scenario (million nominal $)	WEC Payments in Policy Scenario (million 2019$)	SC-CH_4 Values at 2% Near-Term Discount Rate (2019$ per metric ton)	Climate Damages from Emissions Subject to WEC (million 2019$)[a]
2024	830	$900	$750	$620	$1,900	$1,600
2025	650	$1,200	$770	$630	$2,000	$1,300
2026	430	$1,500	$640	$510	$2,100	$890
2027	9	$1,500	$13	$10	$2,200	$18
2028	9	$1,500	$13	$10	$2,200	$19
2029	9	$1,500	$13	$10	$2,300	$20
2030	9	$1,500	$13	$9	$2,400	$20
2031	9	$1,500	$13	$9	$2,500	$21
2032	9	$1,500	$13	$9	$2,500	$21
2033	9	$1,500	$13	$9	$2,600	$21
2034	9	$1,500	$13	$8	$2,700	$21
2035	9	$1,500	$13	$8	$2,800	$21
Total 2024-2035	2,000	-	$2,300	$1,800	-	$4,000

[a] Climate damages are based on remaining methane emissions subject to WEC after accounting for emissions reductions and are calculated using three different estimates of the social cost of methane (SC-CH4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH4 at the 2 percent near-term Ramsey discount rate.

7.4 Uncertainties and Limitations

Throughout the RIA we considered several sources of uncertainty regarding the emissions reductions, benefits, costs, and transfer payments estimated for the proposed rule. We summarize some of the key elements of our discussions of uncertainty below.

Interactions with other policies impacting methane from the oil and natural gas industry: In addition to the WEC, the EPA is currently undertaking several other actions that impact methane emissions from the oil and natural gas industry. In particular, the WEC has important interactions with revisions to GHGRP Subpart W and the NSPS OOOOb and EG OOOOc for the

Oil and Natural Gas Sector. Considerations in the interactions of these policies are discussed in Section 2.3 and in further detail in Section 8.

Projection methods and assumptions: Because the WEC is assessed by facility and WEC obligated party, detailed reporting data and projections are needed to estimate potential WEC obligations and impacts of the proposal. However, facility-specific trends may diverge significantly from overall trends that are used to generate the baseline emissions and throughput projections. In addition, because the projections begin from RY 2021 Subpart W reported data, the projections reflect details in that data which are likely to shift over time. For example, oil and natural gas assets are frequently bought and sold by different companies, which could potentially impact the effects of netting as part of WEC calculations, but it isn’t possible to project how ownership changes may impact WEC obligations.

Methane mitigation potential analysis: Estimates of methane emissions reductions resulting from the WEC depend in part on the characterization of mitigation technologies in the MACC analysis. Section 5.1 discusses important assumptions included in that analysis. Mitigation technology costs faced by different oil and natural gas companies may vary from the assumptions used in the MAC model. Mitigation costs vary by segment and may also vary based on site-specific or operator-specific factors. Where possible, EPA has utilized information specific to the different segments of the oil and natural gas industry, and reflecting several model site types. However, various factors that affect cost and emissions reductions are uncertain and the range of variation cannot be fully captured by the marginal abatement cost analysis. Actual mitigation activities induced by the WEC may be higher or lower than are estimated here. Additional information on the mitigation technologies characterized in the analysis is available in Appendix C to this RIA.

Oil and natural gas market impact analysis: The oil and natural gas market impact analysis presented in this RIA is subject to several caveats and limitations. The market impact analysis depends on uncertain input parameters and assumptions regarding market structure. A more detailed discussion of the caveats and limitations of the oil and natural gas market analysis can be found in Section 5.2.

Monetized methane-related climate benefits: The EPA considered the uncertainty associated with the social cost of methane (SC-CH_4) estimates, which were used to calculate the monetized climate benefits of the decrease in methane emissions projected because of this action. Section 6.1 provides a detailed discussion of the limitations and uncertainties associated with the SC-CH_4 estimates used in this analysis and describes ways in which the modeling addresses quantified sources of uncertainty.

Monetized VOC-related ozone benefits: The illustrative screening analysis described in Appendix A includes many data sources as inputs that are each subject to uncertainty. Input parameters include projected emissions inventories, projected mitigation actions, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). When compounded, even small uncertainties can greatly influence the size of the total quantified benefits.

8 UNCERTAINTY ANALYSES

8.1 Sensitivity on GHGRP Calculation Methods

On August 1, 2023, the EPA proposed revisions to the requirements of Subpart W consistent with directives in the Inflation Reduction Act (referred to in this section as the 2023 Subpart W proposal). The 2023 Subpart W proposal includes a number of proposed changes that could significantly change reported methane emissions and the resulting potential WEC obligations. The changes can be categorized as:

- new reported emissions sources, such as “other large release events” and crankcase venting, and existing sources required for more segments;
- changes to emissions factors used in some existing calculation methods, such as changes in the fugitive emissions factors used in the population method for fugitive emissions in onshore production and gathering and boosting;
- new calculation methods, especially those involving site- or reporter-specific measurements or data, such as new measurement methods for equipment leaks and new leaker factor methods for pneumatic controllers; and
- changes may result in additional reporters to GHGRP Subpart W which have not reported in past years.

EPA does not currently have a quantitative estimate of expected emissions reporting inclusive of all of these proposed revisions. Some qualitative factors in how they will influence reported emissions and the results of this RIA are discussed below.

*New emissions sou*rces. The addition of new reporting emissions sources will increase overall methane reported to Subpart W and subject to the requirements of the WEC. However, in particular with respect to other large release events it is difficult to estimate the magnitude of emissions that will be reported and which facilities will report those emissions.

Changes to emissions factors. Changes to emissions factors have complicated potential effects. For example, the 2023 Subpart W proposal significantly increases the emissions factors used for the population method for equipment leaks in onshore production and gathering and boosting. In RY 2021, most facilities and equipment leak emissions were calculated using the population method. If we assume that these reporters continue to use the population method, then their reported emissions would increase significantly. However, the population method is not the only available method for reporting equipment leak emissions, and higher fugitive emissions factors that more accurately reflect potential emissions in the absence of fugitive monitoring also increase the economic incentive to perform equipment leak monitoring and repair and to report using other calculation methods for fugitives. In addition, EPA expects that as more oil and natural gas operations become subject to fugitive monitoring requirements under the NSPS OOOOb/EG OOOOc that more facilities will switch to other calculation methods for equipment leaks. For other source categories, switching between methods may be less important. For example, switching between methods is less likely in the case of combustion slip emissions, and so the proposed increase in emissions factors related to combustion slip is likely to lead to higher reported methane emissions.

New reporting methods. It is particularly uncertain what emissions will be reported using new calculation methods utilizing site- or reporter-specific measurements. Measurements or reporter-specific data might lead to significantly higher or lower emissions than would have been calculated under other methods. When choosing whether to report using a reporter-specific measurement or using a default emissions factor, reporters are expected to choose calculation approaches that minimize WEC obligations. Thus, holding other calculation methods constant, the addition of optional measurement methods is likely to reduce reported emissions and WEC obligations. However, in some cases GHGRP reporters are required to report based on measurements or surveys that they have conducted. For example, where reporters have performed fugitive emissions surveys pursuant to NSPS requirements, they are required to report leaks found through those surveys. For the purpose of estimating WEC obligations, EPA would further need to make assumptions about how measurements would affect the distribution of reported emissions by individual facilities in relation to throughput. Measurements may vary significantly between different oil and natural gas operators, making it infeasible to estimate the impact of these methods on potential WEC obligations.

New reporters. Several proposed changes in 2023 Subpart W proposal and the 2023 GHGRP supplemental proposal which included revisions to general provisions may result in additional reporters who have not been required to report to GHGRP in the past. For example, the GHGRP supplemental proposal includes an increase in GWP of methane from 25 to 28, and may lead more oil and natural gas facilities to exceed the 25,000 CO_2e reporting threshold. Similarly, the addition of new reporting source categories may bring facilities that were previously below the reporting threshold above 25,000 metric tons CO_2e. New reporting facilities would increase the overall baseline used in this RIA, but information on the emissions intensity of these new reporters is unavailable. Even if total reported methane to Subpart W increases, total WEC-applicable emissions may not be increased significantly.

8.2 Sensitivity on Interaction with NSPS/EG

The WEC has important interactions and is designed to complement the Oil and Gas NSPS OOOOb and EG OOOOc. Because of these interactions, the requirements and implementation of the NSPS OOOOb/EG OOOOc influence the reductions and impacts of the proposed WEC. To the extent that oil and natural gas companies implement strong emissions controls because of requirements in the NSPS OOOOb/EG OOOOc, emissions reductions resulting from the WEC and WEC obligations would be lower than if less stringent emissions controls were required under the NSPS OOOOb/EG OOOOc. To the extent that NSPS OOOOb/EG OOOOc implementation is delayed relative to the planned schedule, the WEC may serve as a partial backstop to ensure that cost-effective mitigation actions are implemented promptly.

The EPA proposed updates to the Oil and Gas NSPS/EG in 2021, published a supplemental proposal in 2022, and finalized rules in December 2023. In addition to requirements already in place, these proposals include standards for many of the major sources of methane emissions in the oil and natural gas industry. The revised NSPS includes new requirements for new and modified facilities, while the EG OOOOc includes requirements for existing sources, which are to be implemented by the states via state regulations and state implementation plans.

There is significant overlap in both the oil and natural gas operations subject to the WEC and the NSPS OOOOb/EG OOOOc and the emissions reduction measures that could be taken to avoid WEC obligations and those potentially required under the NSPS OOOOb/EG OOOOc. On the one hand, the scope of operations impacted by the WEC is a subset of those affected by the NSPS OOOOb and EG OOOOc because the WEC applies only to facilities reporting more than 25,000 tons CO2e to Subpart W and which exceed waste emissions threshold levels with respect to intensity. On the other hand, the scope of equipment and emissions sources affected by the NSPS OOOOb and EG OOOOc is a subset of the reported emissions sources and equipment for which GHGRP facilities report methane emissions.

With respect to overlap in oil and natural gas operations, the scope or coverage of GHGRP Subpart W reporting coverage varies by segment. For example, in RY 2021 emissions were reported to GHGRP related to approximately 500,000 oil and natural gas onshore production wells, out of over 900,000 producing wells in 2021 (EIA, 2022). Because GHGRP reporters skew towards higher-production wells, the proportion of total emissions or oil and natural gas production covered by GHGRP Subpart W reports is significantly higher than the proportion of producing wells. By contrast, because the ownership structure and operations of natural gas gathering and boosting tends to be more concentrated than onshore production, more than 95% of gathering and boosting facilities are estimated to report to GHGRP. Regardless, in both the onshore production and gathering and boosting segments of the oil and natural gas industry, many operators are subject to both the requirements of the proposed WEC and the NSPS OOOOb/EG OOOOc.

With respect to overlap in emissions sources and mitigation actions relevant to both the WEC and the NSPS OOOOb/EG OOOOc, emissions sources with requirements under the NSPS/EG make up a majority of methane emission reported to Subpart W. Many of the most cost-effective methane mitigation options estimated in the MACC correspond to sources and requirements under the NSPS/EG. The Final NSPS OOOOb/EG OOOOc RIA estimated methane emissions reductions associated with fugitive emission, natural gas driven pneumatic controllers, pneumatic pumps, reciprocating compressors, centrifugal compressors, liquids unloading, storage vessels, and associated gas. These sources make up about 80% of methane emissions reported to Subpart W.

Because the WEC and Oil and Gas NSPS OOOOb/EG OOOOc apply to overlapping facilities and emissions sources, the emissions reduction and mitigation costs of the two policies can be thought of as complementary. To the extent that more emissions reductions (and costs) result from the NSPS OOOOb/EG OOOOc, the expected emissions reductions (and costs) resulting from the WEC would be expected to be lower.

9 DISTRIBUTIONAL AND ECONOMIC ANALYSES

9.1 Small Business Analysis

9.1.1 Background for Small Entity Impacts

The EPA evaluated the impacts of the proposed revisions where it identified small entities could potentially be affected and considered whether additional measures to minimize impacts were needed. In evaluating the impacts of the proposed revisions, the EPA assessed the costs and impacts to small entities from the WEC. Because the WEC is a charge on emissions exceeding specific methane intensity thresholds and does not impose emissions standards or require implementation of technologies or work practices, estimated costs for the purposes of the small entity impact analysis were based only on the WEC and do not include costs associated with reducing emissions below the specified methane intensity thresholds. An assessment of costs for individual facilities to achieve the methane intensity thresholds is also inappropriate for the small entity analysis due to the impact of netting across multiple facilities. For many WEC Obligated Parties (i.e., reported facility owners or operators), total WEC is based on the methane intensity performance of multiple facilities, and reduction of methane intensity at an individual facility may or may not impact total WEC. These costs were therefore evaluated at the WEC Entity level to account for netting of emissions from facilities under common ownership or control. Costs are based on the WEC impact in 2024, applying a charge of $900 per metric ton of methane.

9.1.2 Methodology for Calculating Small Entity Impacts

To evaluate whether this proposed rule would have a significant economic impact on a substantial number of small entities, the EPA evaluated the costs of the proposed rule on small entities identified in the RY 2021 subpart W dataset. The EPA used reported facility-to-parent company and facility-to-owner or operator data to link facilities to WEC Obligated Parties. While the EPA recognizes there have been mergers and acquisitions since the end of 2021 that impact facility ownership, there are no available data that track these changes at the subpart W facility level, nor is there any means to project any additional ownership changes that may occur through the end of 2024. Reported 2021 ownership structures were therefore held constant for the small entity impact analysis. Revisions were made to the RY 2021 data to project RY 2024 methane intensity at the facility level. These include:

- Methane emissions data were projected forward from 2021 to 2024 using the 2016-2021 annual segment-specific rate of change in reported methane emissions for each segment of subpart W applicable to WEC
- Total facility CO_2e in 2024 was recalculated using the projected methane emissions data and application of AR5 GWPs for methane and N_2O (no changes to actual N_2O or CH_4 emissions were made). Projected CO_2e was used to determine if facilities would exceed the WEC applicability threshold of reported subpart W emissions equal to or greater than 25,000 metric tons CO_2e
- Throughput volumes were projected forward from 2021 to 2024 using the 2022-2030 annual rate of change for dry natural gas production in the Energy Information Administration's 2023 Annual Energy Outlook. The dry gas production rate of change was to project forward throughput for all subpart W segments; the rate of change for crude oil and lease condensate production was applied to onshore and offshore production facilities that report zero gas sales.

In order to analyze the impacts on the entities subject to the WEC, the EPA employed a survey-like approach. The survey approach consists of review of available reported or solicited data from a sample of facilities that are representative of the total population of affected facilities, in order to estimate the likelihood of impacts on small entities in the total population. However, instead of drawing a small, representative sample, the EPA sampled every unit in the universe of parent entities in a current reporting facility. Business information was available for a large proportion of parent entities, and those with no available information were treated as non-responders.

The survey approach is based on a survey of the full population of current subpart W reporters and their parent entities. The survey estimates the business size distribution and the annual revenues for each parent company, which are compared to the estimated WEC costs of each parent company's associated facility owner or operator. For the survey approach, the EPA reviewed the available RY 2021 data for owners or operators of subpart W facilities to determine whether the reporters were part of a small entity and whether the annualized costs of the proposal would have a significant impact on a substantial number of small entities. The survey approach included the following steps:

1. Soliciting business information from each parent entity for the survey, including a listing of all facilities that the parent entity has an ownership stake in.

2. Classifying parent entities with available employment and revenue data as small or “not small.”
3. Mapping facility parent entities to facility owners or operators.
4. Classifying facility owners or operators as small or “not small” based on the classification of their parent entities.
5. Analyzing expected costs and assigning cost-to-revenue ratios for facility owners or operators.

Soliciting business information. To obtain the employment and revenue data for each of the RY 2021 subpart W parent entities, the EPA reviewed information from ZoomInfo, Experian, and D&B Hoovers business databases in a three-step process. Using an approximate string-matching algorithm, the list of operators was first merged with business information from ZoomInfo for approximately 86% of subpart W parent entities. The remaining unmatched operators were matched to the Experian business database when possible. Additionally, a small number of operators were matched with the D&B Hoovers database information that was collected as part of the Regulatory Impact Analysis (RIA) for the supplemental notice of proposed rulemaking titled “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.” This matching process added information on the ultimate parent entities, number of employees, and annual revenues of the operators. The matches were examined and, when necessary, manual adjustments were made to the matched list of ultimate parent entities to standardize company names, revenue, and employment information. Revenue and employment data were identified for 468 of 472 Subpart W parent entities.

Classifying small businesses. Each subpart W parent company’s NAICS codes that were reported to subpart A (40 CFR 98.3(c)(10)) for RY 2021 were used in conjunction with revenue and/or employment data to classify the company as either “small business” or “not small business.” NAICS codes are reported at the facility level under subpart A. Therefore, the company’s employment and revenue data were evaluated against the Small Business Association (SBA) size classification threshold associated with the relevant NAICS code(s) for the facilities owned by the company. If a company reported emissions to subpart W from facilities with different NAICS codes, then the NAICS code for each of their owned facilities was evaluated against the SBA size classification thresholds. For example, if a company reported one facility under onshore petroleum and natural gas production (NAICS code 211130) and another facility under onshore natural gas transmission compression (NAICS code 486210), then the company’s employment and revenue data was compared to the small business thresholds for both NAICS codes (211130 and 486210). If either NAICS code threshold comparison indicated that the company was a small business, then the company was designated as a small business for the purposes of this analysis. This approach was taken to conservatively identify all potential small entities that may be subject to subpart W; therefore, it is likely that some entities identified as “Small” may not reflect true small entities. Additionally, the classification also reflects only U.S. reported revenues. The entities for which revenue and employee data were not identified were assumed to be small businesses.

Mapping parents to WEC Obligated Parties. Because the proposed rule uses facility owners or operators as the WEC Obligated Party, parent companies must be mapped to owners or operators. For facilities with a single parent company and a single owner or operator, the reported owner or operator was mapped to the reported parent company. The proposed rule also uses a Designated Company approach under which all tons of methane from a facility with multiple parent companies are allocated to a single WEC Obligated Party. For these facilities, the assigned WEC Obligated Party was the owner or operator that mapped to the parent company with the largest equity share in the facility. For facilities with parent companies that had equal equity share in the facility but a single owner or operator, the WEC Entity was mapped to the parent company associated with that owner or operator (e.g., an owner or operator whose name indicated it was a subsidiary of one of the parent companies). For facilities with parent companies that had equal equity share in the facility and an owner or operator associated with each parent company, the WEC Entity was mapped to the parent company with operational control of the facility (based on an internet search). For facilities with multiple parent companies but a single owner or operator that could not be linked to any of the parent companies, the owner or operator was mapped to the parent company with the largest equity share in the facility. For all facilities, the assigned WEC Entity (i.e., owner or operator) was classified as a small business or not small business based on the classification of its parent company.

Analyzing expected costs to WEC obligated parties and assigning cost-to-revenue ratios. To estimate expected costs to reported owners or operators, the EPA calculated the facility-level tons of methane emissions above or below the waste emissions thresholds, summed facility-level tons across facilities under common ownership or control of each WEC Obligated Party to calculate net tons of methane, and multiplied any positive value by $900 to calculate total cost.

There would be no costs for WEC Obligated Parties with netted tons of methane equal to or below zero. WEC costs for 2024 were estimated using the emissions and throughput projections described in section 9.1.1 and the WEC calculation steps described below.

- **Identify WEC applicable facilities**. WEC applicable facilities are GHGRP facilities that report more than 25,000 metric tons CO_2e to GHGRP Subpart W and report emissions under any of the nine oil and natural gas industry segments subject to the WEC (all segments except the natural gas distribution segment). Facilities projected to report less than 25,000 metric tons CO_2e to Subpart W in a given year would not be considered subject to the WEC and are not included in projections of WEC-applicable emissions. Emissions of CO_2 and N_2O reported to Subpart W were assumed to be fixed for each facility at the same level as reported in RY 2021. Methane emissions were projected by segment and source as described section 9.1.1.
- **Calculate facility waste emissions threshold from segment-specific methane intensity thresholds**. To calculate a facility's projected waste emissions threshold, the facility's projected natural gas throughput was first multiplied by the appropriate segment-specific methane intensity threshold to calculate the volume of gas equivalent to the segment-specific methane intensity threshold. These values were converted to metric tons by multiplying by the density of methane (0.0192 mt / Mscf) to calculate the waste emissions threshold in metric tons of methane. The segment-specific methane intensity thresholds for each segment are listed in Table 1-1.
- **Calculate facility tons above or below waste emissions threshold, or WEC applicable emissions**. A facility's projected waste emissions threshold was subtracted from the facility's projected methane emissions to determine the total facility applicable emissions. This analysis conservatively did not consider the impact of exemptions, so the total facility applicable emissions are equal to the WEC applicable emissions. A negative value represented the metric tons of methane emissions a facility was below the waste emissions threshold while a positive value represented the metric tons of methane emissions at the facility that exceeded the segment-specific methane intensity threshold. Facilities with projected subpart W emissions below 25,000 metric tons CO_2e were not considered eligible for the purpose of netting and positive or negative tons from these facilities were excluded.
- **Calculate net WEC emissions by owner-operator**. For WEC Obligated Parties with common ownership or control of multiple facilities, facility tons above or below the waste emissions thresholds were summed across all facilities to calculate net tons.
- **Calculate potential WEC obligations**. WEC Obligated Parties with net tons methane of zero or below would not be subject to the WEC and have zero WEC obligations. For WEC Obligated Parties with net tons methane greater than zero, net tons were multiplied by the WEC, which for 2024 is $900/ton of methane.

To estimate small business impacts, the EPA conducted an analysis to estimate the cost-to-revenue ratio (CRR) based on the total 2024 WEC costs and the reported revenues. Because revenue data were available for the majority of parent companies but only a small number of owners or operators, parent company revenue was used to calculate CRR for each WEC Obligated Parties. Estimated CRR were calculated for each WEC Obligated Parties by dividing total WEC costs by reported revenue data.

Revenue data were not found for two WEC Obligated Parties. These entities had net methane tons of less than zero tons, and thus would not be subject to the WEC and would have CRR of zero; revenue data were therefore not needed for these WEC Obligated Parties.

9.1.3 Results and Conclusions of Small Entity Impacts Analysis

The number of small entities potentially affected by the proposed WEC regulation were estimated based on the information collected for 785 WEC Obligated Parties. Of these, 439 were identified as small entities. Table 9-1 below shows the percent of small entities estimated to have a cost-to-revenue ratio that exceeds 1% or 3%. Since this analysis relied, in part, upon confidential business information (CBI) reported under Subpart W to estimate these impacts, we present only aggregated data and will not provide economic impact estimates by firm.

Table 9-1 Small Entity Cost-to-Revenue-Ratio Threshold Analysis Results

WEC Obligated Parties	785
Small Entity WEC Obligated Parties	439
Number of Small Entities with a CRR >1%	101
Percent of Small Entities with a CRR >1%	21%
Number of Small Entities with a CRR >3%	76
Percent of Small Entities with a CRR >3%	17%

After considering the economic impact of the proposed rule on small entities, EPA has concluded that the proposed rule costs would not likely have a significant impact on a substantial number of small entities. Although the screening analysis suggests that some small entities may have cost-to-revenue ratios that exceed 3%, the EPA's evaluation of the impacts to small entities relied on several methodologies involving conservative assumptions. Therefore, this evaluation likely overestimates the potential impacts on small entities. For example, the identification and classification of subpart W parent entities reporting under more than one NAICS code resulted in a designation of "small" based on whether the business information available met the SBA size classification threshold for a single NAICS code. The classification also reflects only U.S. reported revenues. The Agency is aware that there some WEC obligated parties classified as "small" that are subsidiaries to international corporations, but we are unable to identify the total number of these entities and associated revenues. If such information was known, those WEC obligated parties would likely not be considered as affected small entities. The Agency is also aware that some WEC obligated parties classified as "small" are subsidiaries to private equity firms or banks that would not meet the SBA definition of a small business. Additionally, the individual costs imposed on a facility may be distributed across multiple WEC obligated parties. As a result, the CRRs estimated by WEC obligated party may be overstated.

In addition to the conservative assumptions listed above, there are further mitigating factors not included in this screening analysis that will likely significantly reduce compliance costs, and, as a result, cost-to-revenue-ratios. As discussed in Section 5.1, the compliance cost estimate using only the defined WEC cost does not account for early adoption of mitigation measures that, when implemented, can lower an entity's emissions below the threshold and therefore result in no WEC. Some facilities may find that it is less expensive to invest in mitigation technologies than to pay the WEC. As result, the total compliance cost could be greatly reduced. We estimate that the avoided WEC payments in 2024 resulting from methane mitigation is hundreds of millions of dollars cumulatively across all WEC entities. Over the analysis period, total compliance costs fall as economic abatement options are taken and residual emissions facing WEC payments fall. The cumulative result of this additional analysis that the CRRs estimated here are likely overstated.

Further mitigating factors not included in this screening analysis are evident from the market model analysis described in Section 5.2. Estimates of price elasticities of demand and supply are needed to assess cost pass through. The price elasticity of demand is a measure of the responsiveness of product demand to a change in price of a product. Likewise, the price elasticity of supply is a measure of the responsiveness of supply of a product to a change in its price. Elasticity estimates are used when they are available to provide an indication of how much of the control costs borne directly by firms in affected industries can be passed on to consumers. For example, WEC compliance costs shift supply curves upward. As evidenced by the price elasticities shown in Table 5-4, demand for product from affected producers is inelastic (i.e., the price elasticity of demand is less than 1), indicating there will be a price increase that allows cost pass through to consumers.

The cumulative effect of the above mitigating factors and conservative assumptions used in the screening analysis indicates that, overall, the proposed rule would not likely have a significant impact on a substantial number of small entities.

9.2 Employment Impacts

This section provides background information on employment in natural gas extraction, transmission, and distribution sectors as well as an estimate of the likely employment impacts of the WEC. For the latter, we consider employment impacts in other sectors that will provide installation and manufacturing services to support expected methane abatement activity.

9.2.1 Background

Table 9-2 shows employment in three sectors related to the oil and gas industry based on data provided by the Bureau of Labor Statistics (BLS): oil and gas extraction (NAICS 2111), pipeline transportation of natural gas (NAICS 486210), and natural gas distribution (NAICS 221210).[49] In total, about 263,000 people were employed by the three sectors in 2022, with oil and gas extraction employing the largest number and natural gas distribution only slightly fewer.

Table 9-2 Employment in Oil and Gas Sectors (2022)

NAICS	Sector	Employment (thousands)
2111	Oil and gas extraction	119.3
486210	Pipeline transportation of natural gas	31.1
221210	Natural gas distribution	112.8
Total		**263.2**

Federal Reserve employment data report annual sectoral employment. Employment in oil and gas extraction has declined 39% since 2015, dropping from 195 thousand employees in 2015 to 119 thousand employees in 2022. Employment has remained steady in pipeline transportation

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[49] Retrieved from FRED: IPUCN221210W200000000 (221210), IPUIN486210W200000000 (486210), IPUBN2111U121000000 (2111)

and natural gas distribution, with consistent levels over the past decade. Collectively, employment across the three sectors has declined 22% from 338 thousand in 2015 to 263 thousand in 2022.

Table 9-3 shows total labor compensation in NAICS 2111 and 221210 based on data provided from the Bureau of Labor Statistics (BLS).[50] Labor compensation is defined as payroll plus supplemental payments, and includes salaries, wages, commissions, dismissal pay, bonuses, vacation and sick leave pay, and compensation in kind. In total, the two sectors provided $48.7 billion in labor compensation. Per worker, the oil and gas extraction sector provided $253.3 thousand, while natural gas distribution provided $163.4 thousand. The Economic Census provides wage data for additional 6-digit NAICs codes every five years, with 2012 and 2017 being the latest available.[51]

Table 9-3 Labor Compensation in the Oil and Gas Sector (2022)

NAICS	Sector	Total Labor Compensation (billions)	Total Compensation per Worker (thousands)
2111	Oil and gas extraction	$30.2	$253.3
221210	Natural gas distribution	$18.4	$163.4

While total labor compensation in the oil and gas extraction sector has declined in the last decade due to fewer employees, total compensation per employee has risen from $195.6 thousand in 2012 to $253.3 thousand in 2022. Total labor compensation in natural gas distribution has risen from $13.4 billion in 2012 to $18.4 billion in 2022, and compensation per worker has risen from $122.6 thousand in 2012 to $163.4 thousand in 2022.

The BLS Office of Productivity and Technology (OPT) also measures sectoral output per worker, a measure of labor productivity, for select sectors.[52] In oil and gas extraction (2111), output-per-worker has nearly tripled over the past decade. In natural gas distribution (221210), labor productivity has increased 23%. Output has risen sharply in 2021 and 2022, from an

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[50] Retrieved from FRED: IPUBN2111L020000000 (2111), IPUCN221210L020000000 (221210)
[51] https://data.census.gov/table?q=all+sectors:+summary+statistics&y=2012&n=N0600.00
[52] https://www.bls.gov/productivity/tables/ see labor productivity and costs measures, detailed industries.

average of approximately $100 billion per year for distribution over the period 2012-2020 to $200 billion in 2022. Similarly, oil and gas extraction, while varying more over 2012-202 from $200-400 billion, was $650 billion in 2022.

9.2.2 Employment Impacts

This section presents preliminary analysis of potential employment impacts of the proposed WEC. The analysis is focused on employment within the oil and natural gas industry and does not attempt to model economy-wide employment changes. Oil and natural gas industry employment is potentially affected through each of the cost and emissions impact pathways analyzed in this RIA. Increased expenditures on methane mitigation technologies lead to potential increases in employment because of the labor-intensive nature of some mitigation actions, such as performing fugitive leak detection and repair activities. The energy market impacts lead to reduced employment through reduced production of natural gas. However, based on the analyses in section 5, the costs of methane mitigation are dominant when compared to production changes.

Facilities expecting to pay the WEC will take on abatement activities that allow them to avoid paying the WEC where they can abate for less money. The cost of these activities ise represented by the costs of methane mitigation, characterized in Section 5.1 as the height of the $MACC$. These costs represent expenditures on capital equipment and labor to install and maintain natural gas handling and emissions abatement. As these expenditures are already accounted for within the costs of methane mitigation, they are not additive to societal welfare that has already been characterized, however, because employment is an important economic issue, we identify the value of certain employment supported by abatement expenditures.

This analysis estimates the value of employment induced by the WEC by disaggregating total abatement expenditures, equal to the area under the MACC curve up to total abatement, into capital and operations-and-maintenance. Total capital expenditures represent a mix of capital equipment, labor for construction and installation, and other materials. EPA considers the magnitude of wages paid to construct, operate, and maintain the control equipment (direct employment) and to manufacture control equipment (indirect employment). For oil and natural gas firms that pay the WEC this analysis assumes no associated increased employment, though there may be additional labor demand associated with WEC compliance, reporting, and payment processing for WEC-applicable facilities.

This analysis bases job and wage benefits associated with abatement expenditures on the ratio of employment and wages to total output within sectors that provide emissions abatement services. These ratios are calculated from economic survey data conducted under the Economic Census for a range of North American Industrial Classification System (NAICS) codes. This analysis associates expenditures with an appropriate NAICS codes for capital equipment, installation, and operations and maintenance with NAICS to assign an employment multiplier for each. Table 9-4 presents the multipliers, which range from 0.4 jobs per million dollars of expenditure in natural gas extraction (NAICS code 211130) to 4.3 jobs per million dollars expenditure on capital installation.

Table 9-4 Employment Multipliers for Abatement Expenditures

Expenditure	Type / Segment	NAICS	Employment / $MM Output	Segment Group	Average Employment / $MM
Capital	Equipment	333132	2.72		
	Installation	237120	4.25		
O&M	Oil Extraction	211120	0.60	Production	0.5
	Natural Gas Extraction	211130	0.44		
	Pipeline Transportation	486210	1.11	Gathering, Boosting, Transmission, & Storage (GBTS)	1.0
	Natural Gas Distribution	221210	0.91		
Production	Natural Gas (all segments)	Multiple	0.5		

Direct job impacts of the WEC come from a mix of compliance expenditures (positive) and changes in output (negative). The largest jobs impact comes from capital equipment manufacturing and installation, which support about 200 jobs in 2024 up to about 500 jobs in 2026. Capital and O&M expenditures from the MACC analysis and output changes from the PE Model form the basis of the jobs impacts estimates. The split of capital expenditures between equipment and installation expenditures is assumed to be 70/30. Job losses from reduced output are 2 jobs in 2024 and 33 jobs in 2026 and with none in the remainder of the analysis period. Total jobs supported are about 200 in 2024, rising to about 600 in 2026, and dropping to zero in the later years of the analysis period. Note that job impact estimates are based on employment (i.e., the number of people working in an industry), not full-time equivalent jobs.

Table 9-5 Employment Impacts of Compliance Expenditures and Output Changes

	Capital				**O&M**				**Output**		**Total**
	Equipment		**Installation**		**Production**		**GBTS**				
Multiplier:		**2.7**		**4.3**		**0.5**		**1.0**		**0.5**	
Year	**Exp.**	**Jobs**	**Exp.**	**Jobs**	**Exp.**	**Jobs**	**Exp.**	**Jobs**	**Rev.**	**Jobs**	**Jobs**
2024	$39.4	107	$16.9	72	-$13.3	-7	$24.6	25	-$3.8	-2	195
2025	$74.2	202	$31.8	135	-$19.2	-10	$55.7	56	-$4.2	-2	381
2026	$117.8	320	$50.5	215	$19.4	10	$82.9	84	-$59.5	-33	596
2027	$0.0	0	$0.0	0	$0.9	0	$0.0	0.0	-$1.3	-1	0
2028	$0.0	0	$0.0	0	$0.9	0	$0.0	0	-$1.3	-1	0
2029	$0.0	0	$0.0	0	$0.9	0	$0.0	0	-$1.2	-1	0
2030	$0.0	0	$0.0	0	$0.9	0	$0.0	0	-$1.2	-1	0
2031	$0.0	0	$0.0	0	$0.9	0	$0.0	0	-$1.2	-1	0
2032	$0.0	0	$0.0	0	$0.9	0	$0.0	0	-$1.2	-1	0
2033	$0.0	0	$0.0	0	$0.9	0	$0.0	0	-$1.1	-1	0
2034	$0.0	0	$0.0	0	$0.9	0	$0.0	0	-$1.1	-1	0
2035	$0.0	0	$0.0	0	$0.9	0	$0.0	0	-$1.1	-1	0

9.3 Environmental Justice

9.3.1 Introduction and Background

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on communities with environmental justice concerns in the United States. EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.[53] Executive Order 14008 (86 FR 7619; January 27, 2021) also

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[53] Fair treatment occurs when “no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial

calls on Agencies to make achieving environmental justice part of their missions “by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts.” It also declares a policy “to secure environmental justice and spur economic opportunity for disadvantaged communities that have been historically marginalized and overburdened by pollution and under-investment in housing, transportation, water and wastewater infrastructure and health care.” EPA also released its “Technical Guidance for Assessing Environmental Justice in Regulatory Analysis” (U.S. EPA, 2016) to provide recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time and resource constraints, and analytic challenges will vary by media and circumstance.

A reasonable starting point for assessing the need for a more detailed EJ analysis is to review the available evidence from the published literature and from community input on what factors may make population groups of concern more vulnerable to adverse effects (e.g., underlying risk factors that may contribute to higher exposures and/or impacts). It is also important to evaluate the data and methods available for conducting an EJ analysis. EJ analyses can be grouped into two types, both of which are informative, but not always feasible for a given rulemaking:

1. Baseline: Describes the current (pre-control) distribution of exposures and risk, identifying potential disparities.
2. Policy: Describes the distribution of exposures and risk after the regulatory option(s) have been applied (post-control), identifying how potential disparities change in response to the rulemaking.

EPA’s 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting EJ analyses, though a key consideration is consistency with the

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operations or programs and policies” (U.S. EPA, 2011). Meaningful involvement occurs when “1) potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity [i.e., rulemaking] that will affect their environment and/or health; 2) the population’s contribution can influence [the EPA’s] rulemaking decisions; 3) the concerns of all participants involved will be considered in the decision-making process; and 4) [the EPA will] seek out and facilitate the involvement of population’s potentially affected by EPA’s rulemaking process” (U.S. EPA, 2015). A potential environmental justice concern is defined as “actual or potential lack of fair treatment or meaningful involvement of communities with environmental justice concerns in the development, implementation and enforcement of environmental laws, regulations and policies” (U.S. EPA, 2015). See also https://www.epa.gov/environmentaljustice.

assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options.

9.3.2 Scope and Limitations

The EJ analysis described in this section evaluates only a “baseline” set of environmental justice indicators of 563 counties with methane emissions expected to be affected by the WEC, using the most recent available data. This enables us to characterize communities that in these counties prior to implementation of the proposed rule. We lack key information that we would be needed to assess post-control risks (the “policy” scenario as described above) under the proposed WEC or the regulatory alternatives analyzed in this RIA. Therefore, the extent to which this proposed rule will affect potential EJ outcomes is not quantitatively evaluated.

This proposed action chronologically follows the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Gas Sector (NSPS OOOOb/EG OOOOc, hereafter; (U.S. EPA, 2022c). The RIA for the 2022 Supplemental NSPS OOOOb/EG OOOOc proposal presented a detailed environmental justice analysis of health risks and economic activity associated with the oil and gas industry. EPA expects the WEC implications for environmental justice to be similar to that of the NSPS OOOOb/EG OOOOc rule, as the sources potentially affected by the proposed rule are a subset of those affected by the NSPS OOOOb/EG OOOOc rule, but the projected methane emissions reduction is smaller in magnitude. Time and resource constraints prevent the replication of the series of analyses conducted for the NSPS OOOOb/EG OOOOc. This chapter presents a summary of the NSPS OOOOb/EG OOOOc findings that are expected to be relevant to the current proposal, in addition to presenting a baseline analysis of communities proximate to potentially affected sources. In addition to demographic and health risk indicators addressed by the NSPS OOOOb/EG OOOOc RIA, this analysis shows results for two additional health indicators. This chapter does not address the full range of issues analyzed in the 2022 Supplemental NSPS OOOOb/EG OOOOc RIA. The final NSPS OOOOb/EG OOOOc RIA uses an approach different from the analysis of these issues from the supplemental RIA.

The scope of this analysis is to present a “snapshot” of the characteristics of the communities in these counties and the quantified risks these communities currently face, compared to the national average.

9.3.3 Summary Environmental Justice Findings of the NSPS OOOOb/EG OOOOc RIA

9.3.3.1 Ozone from Oil and Natural Gas VOC Emission Impacts

The 2022 Supplemental NSPS OOOOb/EG OOOOc RIA presented an evaluation of the EJ implications of ozone from VOC emissions from the oil and natural gas sector. Analysis of a baseline (pre-control) air quality scenario comparing exposures to ozone formed from VOC emissions from the oil and natural gas sector across races/ethnicities, ages, and sexes. The NSPS OOOOb/EG OOOOc RIA analysis focused comparing exposure differences to determine if risks unequally distributed among population subgroups of interest.

The NSPS OOOOb/EG OOOOc RIA baseline ozone concentration results showed that Native American populations on average may be exposed to a slightly higher concentration of ozone from oil and natural gas VOC emissions than White populations, who, in turn, may on average be exposed to a higher concentration than the overall average for adults of all races/ethnicities and sexes aged 30–99. Similarly, the analysis suggests that Hispanic populations on average are exposed to a slightly higher concentration of ozone from oil and natural gas VOC emissions than both non-Hispanic individuals and the overall average for adults of all races/ethnicities and sexes aged 30–99.

The NSPS OOOOb/EG OOOOc RIA concluded that because of expected reductions in methane emissions, the rule would also contribute to the slight reductions in formation of ground level ozone, with attendant benefits for human health.

For the present proposed Rule, we are not updating the NSPS OOOOb/EG OOOOc RIA analysis, and do not quantify the benefit of this reduction in risk for individual communities. However, we expect this Rule to contribute further reductions in emissions and additional improvements to outcomes for environmental justice communities.

9.3.3.2 Air Toxics Analysis

For the analysis of the environmental justice impacts of the NSPS OOOOb/EG OOOOc Rule on air toxics exposure, the RIA assessed cancer risks from EPA emissions inventories and air modeling. The emissions identified were primarily (97%) non-point sources, and these were modeled essentially as evenly geographically dispersed in across the area of the source county, the RIA provided the caveat that this assumption about the location of these emissions may not be accurate. Additionally, the National Emissions Inventory database for emissions for the oil and gas sector included both sources that would be affected by the regulation, and sources that would not be affected.

The RIA conducted modeling at the level of census block groups and the EPA AEROMOD 4km^2 grid (9km^2 grid for Alaska) for the non-point sources and the 3% of sources (approximately 400 individual point sources) and found the incremental risk due to oil and gas emissions was less than 1 in 1 million for 90 percent of the census blocks with oil and gas emissions. The modeling identified 122 census blocks (with approximately 140,000 people) exposed to risks greater than 50 in 1 million, and 36 census blocks (with approximately 36,000 people) with risks higher than 100 in 1 million.

Of the racial and ethnic minority population identified to be exposed to elevated risks from oil and gas air toxics emissions, Native Americans and those over 64 years old were over-represented (compared to the national average population) but not at the highest exposure levels. People identifying as Hispanic or Latino and ages 0-17 were over-represented in census blocks exposed to the highest risk.

9.3.3.3 Summary of Employment Analysis

In assessing the environmental justice impacts of the NSPS OOOOb/EG OOOOc proposal, the RIA considered the impacts of potential regulation on employment among overburdened or marginalized communities. The RIA notes that a reduction in employment in the oil and natural gas sector may be associated with loss of income for workers in the oil and gas industry, and for oil and gas communities. Oil and gas workers disproportionately identify as White, and have higher income than the national average, but racial and ethnic minorities, are disproportionately represented in oil and gas communities. The RIA also notes large historical swings in oil and gas employment.

9.3.3.4 Summary of Household Expenditures Analysis

The 2022 Supplemental NSPS OOOOb/EG OOOOc RIA analyzes energy expenditures by income quintile and by marginalized groups. The RIA notes that low income, and, to some extent, racial and ethnic minorities are more likely to be negatively impacted by energy price increases. However, the RIA notes that the NSPS OOOOb/EG OOOOc rule is unlikely to have a significant impact on energy prices, and, therefore, that it was unlikely to exacerbate pre-existing energy burden inequality.

The proposed WEC is expected to be similarly unlikely to affect energy prices, and, therefore, is not likely to exacerbate energy burden inequality.

9.3.4 Environmental Justice Analysis of the Proposed Rule

EPA constructed an analysis of reported methane emissions by county in the United States for the facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments with methane emissions that exceed their waste emissions threshold (i.e., their WEC applicable emissions are greater than zero) based on reported RY 2021 emissions and throughputs. We allocated the reported methane emissions for facilities in the Onshore Petroleum and Natural Gas Production industry segment to counties proportional to the number of producing wells the facility reported for each county (which is part of the reported sub-basin identifier). We determined the counties in which each facility in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment operated based on the reported location of acid gas removal units, dehydrators, flare stacks, and atmospheric storage tanks. We then allocated the reported methane emissions evenly across the counties identified.

We used this analysis to identify 563 counties where Onshore Petroleum and Natural Gas Production and/or Onshore Petroleum and Natural Gas Gathering and Boosting facilities with emissions that may be above the waste emissions threshold and therefore subject to the WEC (see Section 4) operated in 2021. These are the counties where emissions might change due to the WEC. See Figure 9-1.

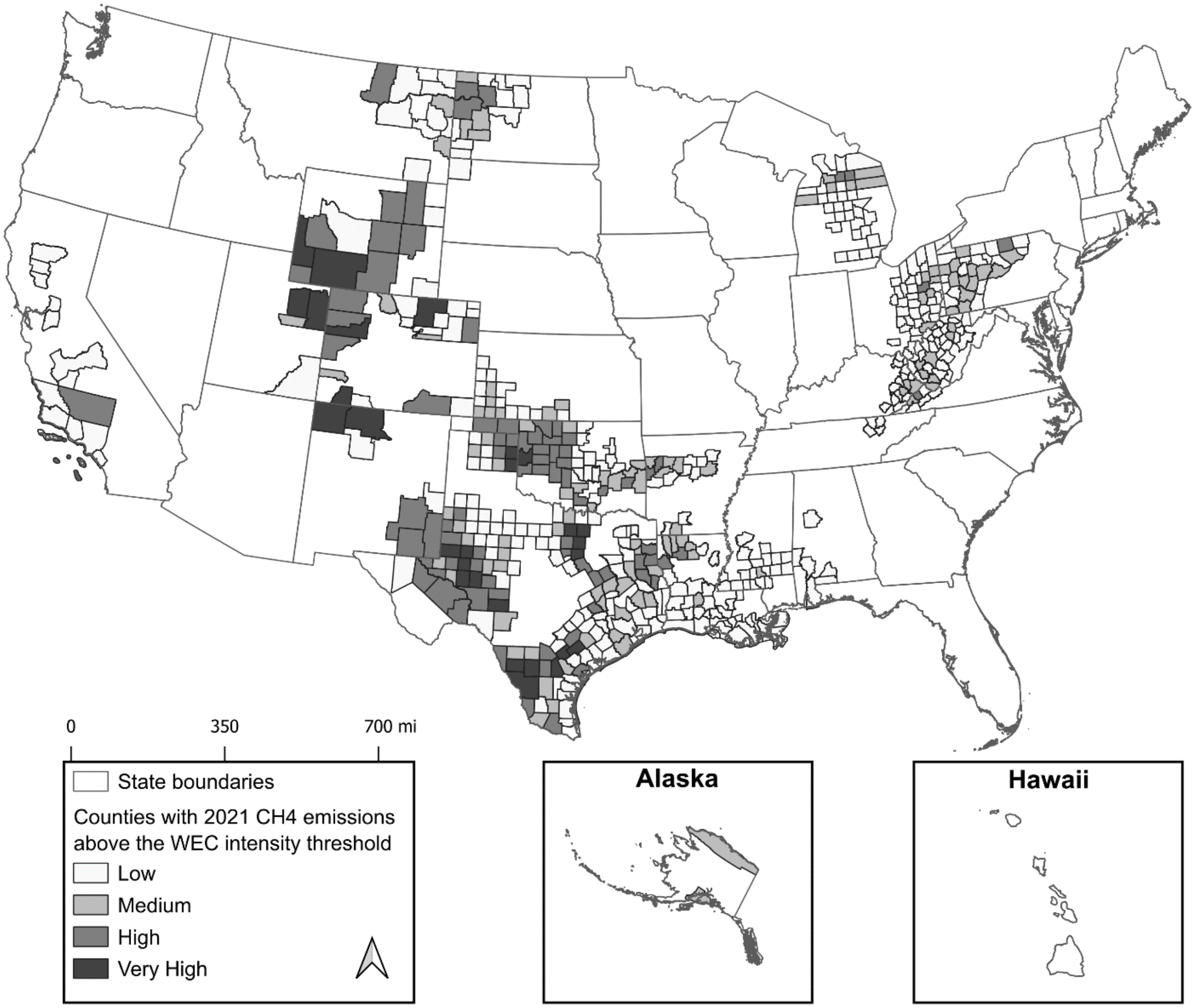

Figure 9-1 Map of the counties identified as having emissions from facilities that are expected to owe the Waste Emissions Charge

As noted above, the analysis in this section is focused on baseline conditions prior to implementation of the proposed rule. Again, we are not able to assess how the proposed rule may affect emissions from specific counties – emissions changes will depend on decisions taken by regulated entities in response to specific local conditions. Consequently, we do not quantify any environmental justice impact of the WEC following its implementation. Importantly, we note that this proposal may not impact all locations with oil and natural gas emissions equally, in part due to differences in existing state regulations in locations like Colorado and California, which have more stringent requirements.

For these counties, we are able to identify certain demographic characteristics of the communities, the incidence of some chronic disease conditions among the populations, and Total Cancer Risk and Total Respiratory Risk for the people in these counties. We compare the baseline data for counties with the emissions to data for counties likely to be affected by the WEC to national averages for the demographic and risk categories. Note that this comparison does not perfectly isolate the correlation between environmental justice concerns and oil and gas production –counties may have oil and gas activity and associated emissions, but may not be subject to the WEC. There are other sources of emissions that contribute to health risks. Additionally, emissions from the oil and gas sector may affect populations downwind of the source county, but for this analysis we are not conducting air transport modeling and limiting analysis to the populations living in the source counties.

Demographic data, including income, race and ethnicity are taken from the most recent (2021) American Communities Survey (ACS) published by the Census Bureau. This data was gathered from 2017-2021. We use the 2021 “PLACES Dataset,” published by the Centers for Disease Control, to gather county-level incidence of asthma and heart disease (specifically “Chronic Asthma Prevalence Among Adults ≥ 18 years,” and “Chronic Heart Disease Prevalence Among Adults ≥ 18 years”). We provide county level cancer risk and respiratory risk at the county level by analyzing the EPA dataset on risks from atmospheric pollution called AirToxScreen. “Total Cancer Risk” is presented as cancers per one million people from a lifetime exposure to a certain level of air pollution, over and above other cancer risks. “Total Respiratory Risk” is a non-cancer hazard quotient, which is exposure to a substance divided by the level of exposure at which no adverse effects are expected – both risk measures are the sum of all individual risk values for the chemicals evaluated in the AirToxScreen database (U.S. EPA, 2023b).

Emissions from the 563 counties range from under one metric ton per year of methane, to more than 50,000 tons per year. We’ve divided the counties into groups based on their respective annual emissions, and compare the average demographic and risk indicators for each category with the averages for the entire group, and with the averages for all U.S. counties. The categories are “low, medium, high, and very high.” (see Table 9-6)

Table 9-6 Categorizing Category Emissions by Intensity

Category Label	County emissions (mt/year)	Percentile	Total Counties	Percent of Total Emissions
Low	<1-643	<60th	339	6%
Medium	643 - 2,329	60th – 80th	109	13%
High	2,329 - 7,863	80th-95th	83	32%
Very High	7,863 – 50,540	>95th	29	49%

These results show that the emissions vary widely, and that the highest emitting counties account for a disproportionate fraction of the total. The top 29 counties, representing 5% of the of the group, contribute nearly 50% of the methane emissions. Emissions from the 339 low emissions counties contributes 6 percent of the total. Figure 9-2 shows emissions from all 563 counties ranked from lowest total annual emissions to highest.

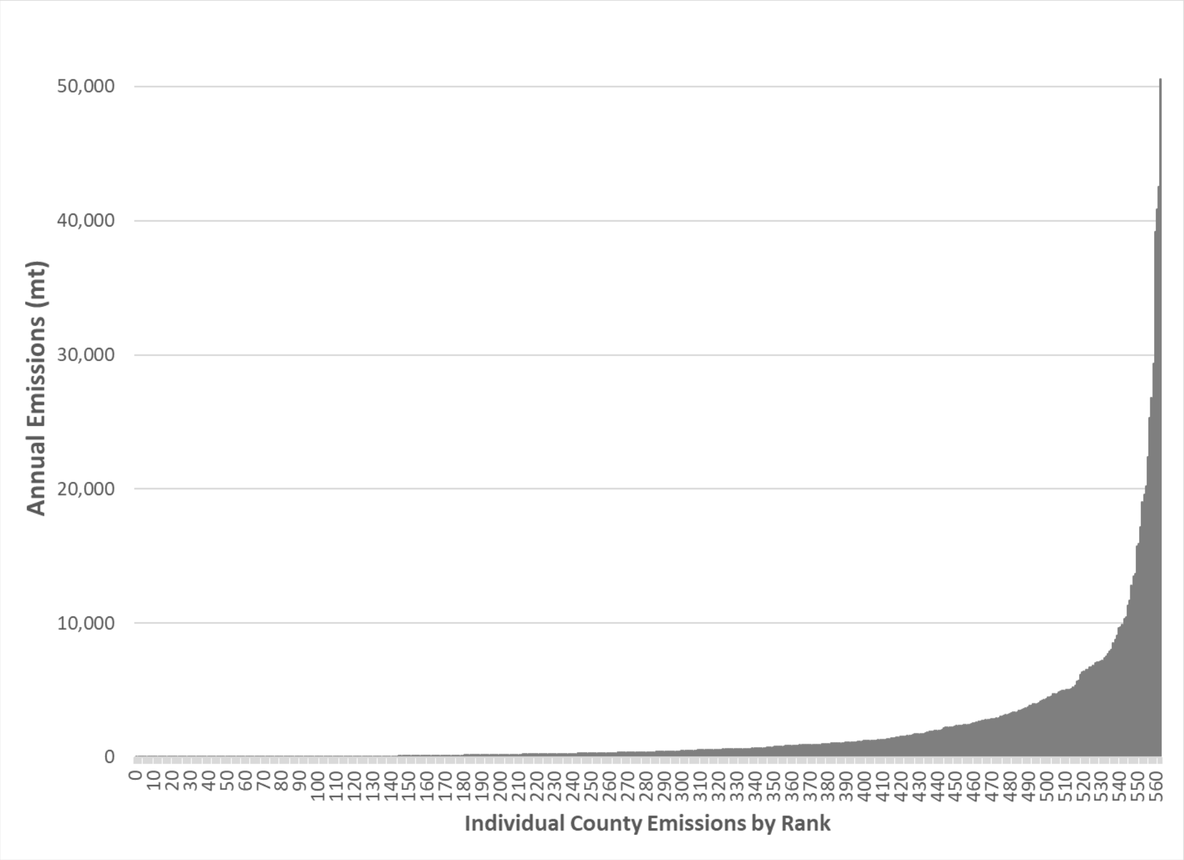

Figure 9-2 Individual County Emissions Ranked from Lowest to Highest

The categorization gives an opportunity to investigate any relationship between county emissions quantity and health risk for communities in these counties. Clearly, there are many potential reasons that emissions identified here may not be directly correlated with risks, even though these emissions are associated with emissions of hazardous air pollution and are precursors to ground level ozone. First, counties are large areas, and populations in counties may not be near oil and gas emissions sources. Second, there are other sources of emissions risks in these counties. Additionally, many of these counties include emissions from the oil and gas sector that are not affected by the proposal, and therefore not quantified in these results. Moreover, many communities in these counties face risks from atmospheric emissions from outside of their county boundaries. It is important to note that these results are averages, and circumstances for communities in individual counties can be very different from the average risks we can show with this data.

9.3.5 Aggregate Average Conditions for Potentially Affected Counties

The data shown in Table 9-7 are taken for each country from the most recent government datasets. The demographic data is from the 2021 American Communities Survey (US Census, 2023). The Total Cancer Risk and Total Respiratory Risk are from the EPA AirToxScreen 2019 database (EPA, 2022d). Chronic Asthma Prevalence among Adults Age ≥ 18 years and Chronic Heart Disease Prevalence among Adults Age ≥ 18 years are from the Center for Disease Control "PLACES" Dataset (CDC, 2022). For each indicator, the national average for the indicator is in the first column (note that national average of 3,143 counties includes the counties in this dataset). The second column includes the averages for all 563 counties identified as having emissions potentially subject to the WEC. The Low Emissions column averages are for the 339 counties with annual methan emissions less than 643 metric tons. The Medium Emissions column shows the indicator averages for the 109 counties with emissions between 643 and 2,329 metric tons. The 83 counties represented in the High Emissions column have emissions between 2,329 and 7,863 metric tons, and the Very High Emission column represents the 29 counties with reported emissions above 7,863 tons (the county with the highest emissions potentially subject to the WEC has reported emissions of 50,540 metric tons of methane).

Looking at all of the potential WEC counties, this analysis shows results that are generally consistent with the main results from the NSPS OOOOb/EG OOOOc RIA analysis. The communities in these counties are generally more diverse than the national average. These counties are home to higher percentages of individuals who identify as being Native American, or who identify as members of race "other" than White, Black or African American, or Native American. There are generally more people who identify as having Hispanic or Latino ethnicity – who are substantially over-represented in the High and Very High Emissions counties. There are generally fewer individuals who identify as Black or African Americans in these counties, with progressively fewer moving from Low to Medium to High emissions counties, but a high percentage (10.6) again in the 29 "Very High Emissions" counties. Native Americans populations are disproportionately represented in these counties - increasingly more so in counties in the higher the emissions category.

While the median household income for these counties is generally lower than the national average, it is higher than the national average in the 29 counties with the highest emissions. Similarly, the households with low incomes (below the Poverty line) and very low incomes (below 50% of the poverty line) are over-represented compared to the national average, there are fewer households with low and very low incomes in the counties with the highest emissions.

Table 9-7 Overall Demographic and Health Indicators for All Counties, by Category

	National Average	**All Potential WEC Counties**	**Low Emissions *(<60th percentile)***	**Medium Emissions *(60th - 80th percentile)***	**High Emissions *(80th-95th percentile)***	**Very High Emissions *(>95th percentile)***
% White (race)	68.1	65.1	62.5	76.9	73.3	66.6
% Black or African American (Race)	12.6	11.1	12.1	9.0	4.3	10.6
% Native American (Race)	0.80	0.97	0.88	0.83	1.3	1.8
% Other (Race)	19.3	23.7	25.4	14.2	22.3	22.8
% Hispanic (Ethnicity)	18.4	26.5	26.3	14.5	42.5	31.7
Median Household Income (1k 2019$)	72.3	68.2	68.6	67.0	57.7	76.5
% Below Poverty Line	6.7	7.7	7.7	7.1	9.7	6.2
% Below Half the Poverty Line	5.6	6.3	6.4	5.8	7.7	5.1
Total Cancer Risk (per million)	25.6	27.4	27.8	26.1	22.4	28.8
Total Respiratory Risk (hazard quotient)	0.31	0.32	0.33	0.29	0.25	0.30
Chronic Asthma Prevalence (≥ 18 yrs)	9.8	9.9	9.9	9.8	9.8	9.4
Chronic Heart Disease Prevalence (≥ 18 yrs)	5.7	5.9	5.7	6.2	6.6	5.6

With regard to the health indicators from the AirToxScreen and PLACES datasets, there appears to be a slight elevation across all health categories for the 563 counties compared to the national averages. However, there does not appear to be a discernable trend in health risks for counties with higher emissions potentially subject to the WEC.

These health indicators are consistent with the findings from the NSPS OOOOb/EG OOOOc RIA: that while ozone and hazardous pollutants from the oil and gas industry are known to present health risks, data at the county level is too aggregated and across too large an area to show the impacts of the emissions on entire county populations.

It is possible, however, that some households in these 563 counties are located in close proximity to sources of emissions and may face higher than average health risks. This analysis indicates that these risks are experienced by communities with environmental justice concerns at a higher percentage. These results suggest additional and continuing analysis of environmental justice concerns for these communities is warranted.

Due to lack of resources, time, and data, it is not possible to conduct a more thorough investigation of the very localized conditions of communities, which include environmental justice communities of concern, that may be affected by the proposed rule. Because the impacts of the rule will depend on decisions about emissions sources that will be made in response to local economic and regulatory conditions, it is not possible to project the impact of the proposed rule on specific communities. EPA believes, however, that in aggregate the proposed action will result in reduction of methane, hazardous air pollutants, and volatile organic compounds, and, generally, this result will improve environmental justice outcomes.

9.4 Distributional Climate Impacts

9.4.1 Environmental Justice Implications of Climate Change

Methane emissions represent a significant share of total GHG emissions and hence are a major contributor to climate change. In 2009, under the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act (“Endangerment Finding”), the Administrator considered how climate change threatens the health and welfare of the U.S. population. As part of that consideration, she also considered risks to communities with environmental justice concerns, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially vulnerable communities; individuals at vulnerable life stages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous or people of color dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the U.S. Global Change Research Program (USGCRP), the IPCC, and the National Academies of Science, Engineering, and Medicine add more evidence that the impacts of climate change raise potential EJ concerns (IPCC, 2018; Oppenheimer et al., 2014; Porter et al., 2014; Smith et al., 2014; USGCRP, 2016, 2018).

These reports conclude that poorer or predominantly non-White communities can be especially vulnerable to climate change impacts because they tend to have limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the U.S. In particular, the 2016 scientific assessment on the Impacts of Climate Change on Human Health found with high confidence that vulnerabilities are place- and time-specific, life stages and ages are linked to immediate and future health impacts, and social determinants of health are linked to greater extent and severity of climate change-related health impacts. The GHG emission reductions associated with this proposal would contribute to efforts to reduce the probability of severe impacts related to climate change. Individuals living in socially and economically disadvantaged communities, such as those living at or below the poverty line or who are experiencing homelessness or social isolation, are at greater risk of health effects from climate change. This is also true with respect to people at vulnerable life stages, specifically women who are pre- and perinatal, or are nursing; in utero fetuses; children at all stages of development; and the elderly. Per the Fourth National Climate Assessment (NCA4), “Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being.” Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in GHGs and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

The scientific assessment literature demonstrates that there are myriad ways these populations may be affected at the individual and community levels. Individuals face differential exposure to criteria pollutants, in part due to the proximities of highways, trains, factories, and other major sources of pollutant-emitting sources to less-affluent residential areas. Outdoor workers, such as construction or utility crews and agricultural laborers, who frequently are comprised of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, individuals within EJ populations of concern face greater housing, clean water, and food insecurity and bear disproportionate economic impacts and health burdens associated with climate change effects. They have less or limited access to healthcare and affordable, adequate health or homeowner insurance. Resiliency and adaptation are more difficult for economically disadvantaged communities: They have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes to limit or reduce the hazards they face. They frequently are less able to self-advocate for resources that would otherwise aid in building resilience and hazard reduction and mitigation.

In a 2021 report, *Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts,* EPA considered the degree to which four socially vulnerable populations— defined based on income, educational attainment, race and ethnicity, and age— may be more exposed to the highest impacts of climate change (U.S. EPA, 2021c). The report found that Blacks and African American populations are approximately 40 percent more likely to currently live in these areas of the U.S. projected to experience the highest increases in mortality rates due to changes in temperature. Additionally, Hispanic and Latino individuals in weather exposed industries were found to be 43 percent more likely to currently live in areas with the highest projected labor hour losses due to temperature changes. American Indian and Alaska Native individuals are projected to be 48 percent more likely to currently live in areas where the highest percentage of land may be inundated by sea level rise. Overall, the report confirmed findings of broader climate science assessments that Americans identifying as people of color, those with low-income, and those without a high school diploma face higher differential risks of experiencing the most damaging impacts of climate change.

The assessment literature cited in EPA's 2009 and 2016 Endangerment and Cause or Contribute Findings, as well as Impacts of Climate Change on Human Health (2016) and the NCA4 (2018), also concluded that certain populations and life stages, including children, are especially sensitive to climate-related health effects. In a more recent 2023 report, *Climate Change Impacts on Children's Health and Well-Being in the U.S.,* EPA considered the degree to which children's health and well-being may be impacted by five climate-related environmental hazards – extreme heat, poor air quality, changes in seasonality, flooding, and different types of infectious diseases (U.S. EPA, 2023c). The report found that children's academic achievement is projected to be reduced by 4-7% per child, as a result of moderate and higher levels of warming, impacting future income levels. The report also projects increases to the numbers of annual emergency department visits associated with asthma and a four to eleven percent increase in new asthma diagnoses due to climate-driven increases in air pollution. In addition, more than 1 million children in coastal regions are projected to be temporarily displaced from their homes annually due to climate-driven flooding, and infectious disease rates are similarly anticipated to rise, with the number of new Lyme disease cases in children living in 22 states in the eastern and midwestern U.S. increasing by approximately 3,000-23,000 per year compared to current levels. Overall, the report confirmed findings of broader climate science assessments that children are uniquely vulnerable to climate-related impacts and that in many situations, children in the U.S. who identify as Black, Indigenous, and People of Color, are limited English-speaking, do not have health insurance, or live in low-income communities may be disproportionately exposed to the most severe impacts of climate change.

Native American Tribal communities possess unique vulnerabilities to climate change, particularly those impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable. The NCA4 noted that while Indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens Indigenous peoples' livelihoods and economies. In addition, there can institutional barriers to their management of water, land, and other natural resources that could impede adaptive measures.

For example, Indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The Confederated Tribes of the Umatilla Indian Reservation in the Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat. Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events.

NCA4 noted that Indigenous peoples often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's, diabetes, and obesity, which can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events. These factors also may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

NCA4 and IPCC Fifth Assessment Report also highlighted several impacts specific to Alaskan Indigenous Peoples. Coastal erosion and permafrost thaw will lead to more coastal erosion, exacerbated risks of winter travel, and damage to buildings, roads, and other infrastructure – these impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's Indigenous people. In terms of food security, the NCA4 discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While the NCA also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

In addition, the U.S. Pacific Islands and the indigenous communities that live there are also uniquely vulnerable to the effects of climate change due to their remote location and geographic isolation. They rely on the land, ocean, and natural resources for their livelihoods, but face challenges in obtaining energy and food supplies that need to be shipped in at high costs. As a result, they face higher energy costs than the rest of the nation and depend on imported fossil fuels for electricity generation and diesel. These challenges exacerbate the climate impacts that the Pacific Islands are experiencing. NCA4 notes that Indigenous peoples of the Pacific are threatened by rising sea levels, diminishing freshwater availability, and negative effects to ecosystem services that threaten these individuals' health and well-being.

9.4.2 Avoided U.S. Climate Impacts of the Proposed Rule

As discussed in the previous section, large-scale impacts resulting from GHG-driven long-term climate change may be experienced differently across populations and regions. This section presents an analysis of the distribution of avoided long-term climate impacts associated with the CH_4 emission reductions from the proposed rule to better understand how the WEC rule may mitigate climate change impacts, and how these changes may be experienced differently by residents across the U.S. Specifically, this analysis uses the Framework for Evaluating Damages and Impacts (FrEDI) (U.S. EPA, 2021a) to illustrate how climate-driven impacts at the end of the century (2090) may be distributed across different sectors, regions, and populations within contiguous U.S. borders. While the impact categories included in this analysis cover a large range across the U.S. economy, FrEDI does not include a comprehensive list of all climate-driven impacts and only explores those effects that directly occur within contiguous U.S. borders. Therefore, FrEDI only provides a subset of the impacts expected to accrue to U.S. citizens and their interests. See Appendix C for additional information on the FrEDI analysis.

Summary of Changes Across Sectors, Regions, and Populations

Annual net[54] climate-driven impacts across all modeled sectors of the U.S. are projected to decrease as a result of methane emission reductions from the proposed rule. These avoided damages are associated with national level reductions in climate-driven impacts on human health, such as changes in temperature-related mortality, climate-driven air quality (ozone and ambient fine particulate matter) related mortality[55], suicide, violent crime, and exposure to wildfire smoke, ambient dust in the Southwest, Vibriosis, and Valley fever; infrastructure-related impacts such as effects on transportation from high-tide flooding, property damage from hurricane winds, and damages to roads and rail; and labor hours lost when temperatures are too hot for workers to work outdoors or in unconditioned workplaces.

Of these analyzed sectors, reductions in climate-driven impacts associated with the proposed rule will not be distributed evenly across different geographic regions. Regional and sectoral differences are driven in part by geographic variations in where climate change damages are projected to occur, the sector being considered, and the current demographic patterns of

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[54] FrEDI evaluates both negative and positive effects of climate change across its sectors, which can geographically vary in sign and magnitude (e.g., warming can lead to decreases in health effects in the Midwest from climate-driven changes in $PM_{2.5}$). At the national level, the net impacts are reduced in all sectors in response to changes in methane emissions from the proposed rule.

[55] The air quality benefits described here are a result of changes in concentrations of ozone and fine particulate matter ($PM_{2.5}$) that are the result of climate-driven changes in meteorology, atmospheric chemistry, and other biogeochemical factors.

where different populations currently live. For example, while the largest avoided climate impacts in each region are associated with reductions in mortality rates from avoided temperature change, the relative reductions in other sectors are projected to vary by region. For example, avoided damages from climate-driven air quality related mortality are second largest in 4 of the 7 FrEDI U.S. regions, avoided damages to transportation infrastructure (e.g., rail and roads) and agriculture are comparatively larger in the Midwest and Northern Plains, and avoided wildfire damages are comparatively larger in the Northwest and Southwest regions. For other sectors, impacts are only expected to occur in select regions, such as climate-driven changes in dust and Valley fever primarily impacting populations living in the Southwest region, and reductions in tropical wind damage and transportation impacts from high-tide flooding largely occurring along coastlines of the Southeast, Southern Plains, and Northeast regions.

Lastly, while all populations are also projected to experience a reduction in net climate-driven impacts from the proposed rule, these avoided impacts will not be evenly distributed across different populations. Understanding the comparative risks to different populations is critical for developing effective and equitable strategies for responding to climate change. Of the four dimensions of social vulnerability considered in this analysis (age, income, education level, and race and ethnicity[56]), BIPOC (Black, Indigenous, and People of Color) individuals aged 65 and older are more likely to live in regions that are projected to see the largest reductions in climate-driven air quality mortality, while those living with low-income are more likely to see larger reductions in avoided lost labor hours due to extreme temperatures. When further considering differences across different races and ethnicities included in this analysis, Blacks and African Americans over the age of 65 are more likely to see greater reductions in climate-driven changes in air quality, while Hispanics and Latinos are more likely to see reductions in lost labor hours, largely driven by the regional differences in where these populations currently live and where avoided climate driven changes are projected to occur due to emission reductions in the proposed rule.

This analysis advances the detailed understanding of the distribution of climate change impacts within U.S. borders (excluding Alaska, Hawaii, and the U.S. territories), and is intended

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[56] Based on the data and methodology presented in a recent EPA report on Climate Change and Social Vulnerability in the United States (U.S. Environmental Protection Agency: Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts, Washington, DC, EPA/430/R-21/003, 2021.).

to provide a snapshot of the different ways U.S. residents are projected to experience fewer climate-driven impacts as a result of the methane reductions from the proposed WEC. See Appendix C for detailed discussion of avoided damages across the 22 impact sectors, 7 regions, and 4 dimensions of social vulnerability included within FrEDI. This distributional assessment is the most detailed and complete to date but is not comprehensive and should therefore be considered a preliminary accounting of climate impacts relevant to U.S. interests.

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ANNEXES

ILLUSTRATIVE SCREENING ANALYSIS OF MONETIZED VOC-RELATED OZONE HEALTH BENEFITS

In this appendix, we present a supplementary screening analysis to estimate potential health benefits from the changes in ozone concentrations resulting from VOC emissions reductions under the proposed rule. As described in detail below, the distribution of the projected change in VOC emissions are subject to significant uncertainties; for this reason, the estimated benefits reported below should not be interpreted as a central estimate and thus are not reflected in the calculated net benefits above. For this analysis, we apply a national benefit-per-ton approach based on photochemical modeling with source apportionment paired with the Environmental Benefits Mapping and Analysis Program (BenMAP) for years between 2024 and 2035 using an April–September average of 8-hr daily maximum (MDA8) ozone metric.

Air Quality Modeling Simulations

The photochemical model simulations are described in detail in U.S. EPA (2021a) and are summarized briefly in this section. The air quality modeling used in this analysis included annual model simulations for the year 2017. The photochemical modeling results for 2017, in conjunction with modeling to characterize the air quality impacts from groups of emissions sources (i.e., source apportionment modeling) and expected emissions changes due to this proposed rule, were used to estimate ozone benefits expected from this proposed rule in the years 2024–2035.

The air quality model simulations (i.e., model runs) were performed using the Comprehensive Air Quality Model with Extensions (CAMx version 7.00) (Ramboll Environ, 2016). The CAMx nationwide modeling domain (i.e., the geographic area included in the modeling) covers all lower 48 states plus adjacent portions of Canada and Mexico using a horizontal grid resolution of 12×12 km shown in Figure A-1.

Figure A-1 Air Quality Modeling Domain

Ozone Model Performance

While U.S. EPA (2021a) provides an overview of model performance, we provide a more detailed assessment here specifically focusing on ozone model performance relevant to the metrics used in this analysis. In this section, we report CAMx model performance for the MDA8 ozone across all days in April-September. While regulatory analyses often focus on model performance on high ozone days relevant to the NAAQS (U.S. EPA, 2018a), here we focus on all days in April-September since the relevant ozone metrics used as inputs into BenMAP use summertime seasonal averages. Model performance information is provided for each of the nine National Oceanic and Atmospheric Administration (NOAA) climate regions in the contiguous US, as shown in Figure A-2 and first described by Karl and Koss (1984).

Table A-1 provides a summary of model performance statistics by region. Normalized Mean Bias was within ±10 percent in every region and within ±5 percent in the Northeast, Ohio Valley, South, Southwest, and West regions. Across all monitoring sites, normalized mean bias was -0.2 percent. Normalized mean error for modeled MDA8 ozone was less than ±20 percent in every region except the Northwest where it was 21 percent. Correlation between the modeled and observed MDA8 ozone values was 0.7 or greater in five of the nine regions (Northeast, Upper Midwest, Southeast, South, and West). In the remaining four regions correlation was 0.69 in the Ohio Valley, 0.64 in the Northern Rockies and Plains, 0.46 in the Southwest, and 0.69 in the Northwest. Across the contiguous U.S. as a whole, the correlation between modeled and measured MDA8 ozone was 0.72.

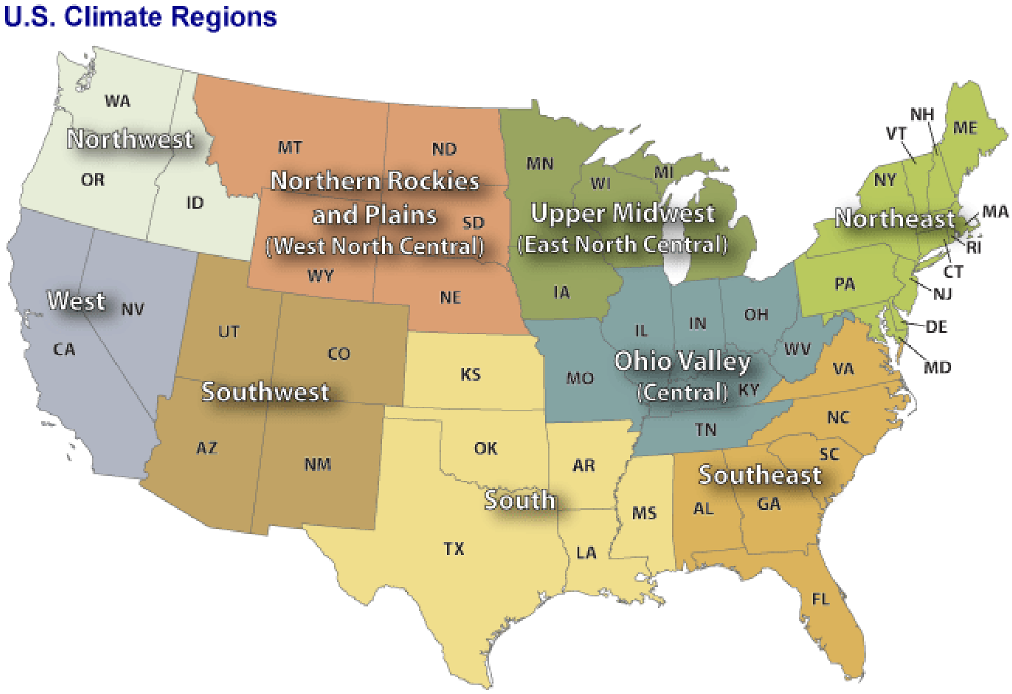

Figure A-2 **Climate Regions Used to Summarize 2017 CAMx Model Performance for Ozone**

Table A-1 **Summary of 2017 CAMx MDA8 ozone model performance for all April–September days**

Region	**Number of Monitoring Sites**	**Mean observed MDA8 (ppb)**	**Mean modeled MDA8 (ppb)**	**Correlation**	**Mean bias (ppb)**	**RMSE (ppb)**	**Normalized mean bias (%)**	**Normalized mean error (%)**
Northeast	189	42.4	42.5	0.71	0.1	9.1	0.3	17.2
Upper Midwest	107	42.5	39.1	0.70	-3.4	9.1	-8.0	17.2
Ohio Valley	236	45.4	45.8	0.69	0.4	8.3	0.8	14.7
Southeast	177	40.2	43.4	0.76	3.3	8.8	8.2	17.7
South	145	42.0	43.5	0.73	1.5	8.8	3.6	16.7
Northern Rockies and Plains	55	46.8	43.1	0.64	-3.7	9.3	-7.9	16.4
Southwest	117	54.3	52.5	0.46	-1.8	10.2	-3.4	15.5
Northwest	28	41.4	44.0	0.69	2.7	12.4	6.4	21.0
West	200	51.6	50.1	0.74	-1.5	10.3	-2.9	16.1
All	**1258**	**45.4**	**45.3**	**0.72**	**-0.1**	**9.3**	**-0.2**	**16.4**

Figure A-3 displays modeled MDA8 normalized mean bias at individual monitoring sites. This figure reveals that the model has slight overpredictions of mean April-September MDA8 ozone in the southeastern portion of the country and along the Pacific coast and slight underpredictions in the northern and western portions of the country. Time series plots of the modeled and observed MDA8 ozone and model performance statistics across the nine regions were developed. Overall, the model closely captures day to day fluctuations in ozone concentrations, although the model had a tendency to underpredict ozone in the earlier portion of the ozone season (April and May) and overpredict in the later portion of the ozone season (July-September) with mixed results in June. This model performance is within the range of other ozone model applications, as reported in scientific studies (Emery et al., 2017; Simon, Baker, & Phillips, 2012). Thus, the model performance results demonstrate the scientific credibility of our 2017 modeling platform. These results provide confidence in the ability of the modeling platform to provide a reasonable projection of expected future year ozone concentrations and contributions.

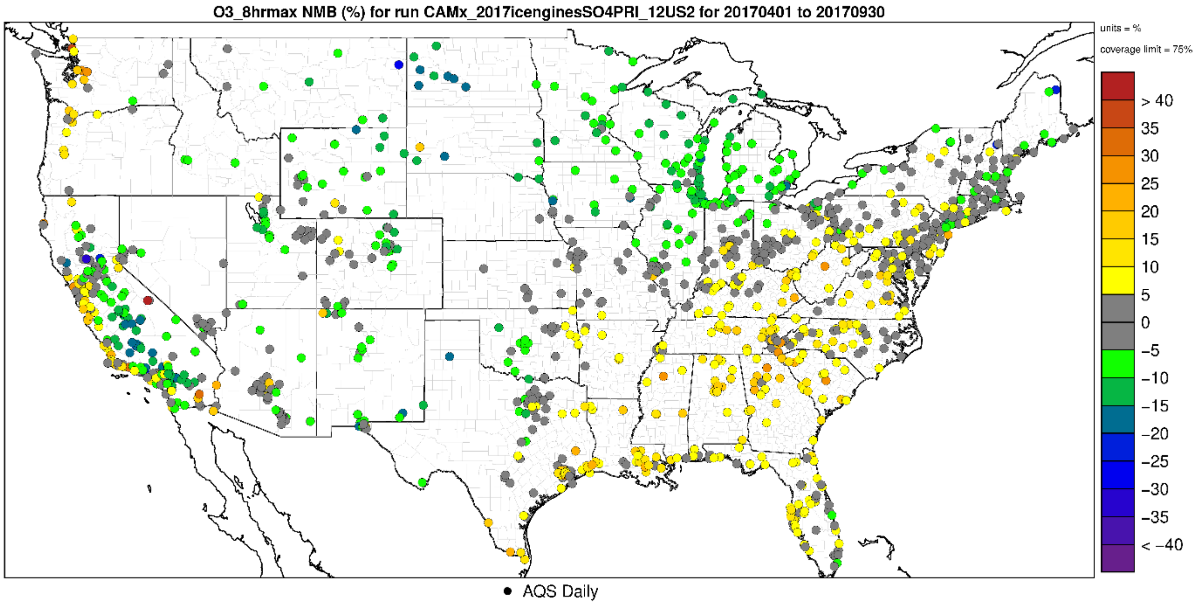

Figure A-3 Map of 2017 CAMx MDA8 Normalized Mean Bias (%) for April–September at all U.S. monitoring sites in the model domain

Source Apportionment Modeling

The contribution of specific emissions sources to ozone in the 2017 modeled case were tracked using a tool called "source apportionment." In general, source apportionment modeling quantifies the air quality concentrations formed from individual, user-defined groups of emissions sources or “tags.” These source tags are tracked through the transport, dispersion, chemical transformation, and deposition processes within the model to obtain hourly gridded contributions from the emissions in each individual tag to hourly modeled concentrations of ozone.

For this analysis ozone contributions were modeled using the Ozone Source Apportionment Technique (OSAT) tool. In this modeling, VOC emissions from oil and natural gas operations were tagged separately for three regions of the U.S. regions. The model-produced gridded hourly ozone contributions from emissions from each of the source tags which we aggregated up to an ozone metric relevant to recent health studies (i.e., the April-September average of the MDA8 ozone concentration). The April-September average of the MDA8 ozone contributions from each regional oil and natural gas tag were summed to produce a spatial field representing national oil and natural gas VOC contributions to ozone across the United States (Figure A-4).

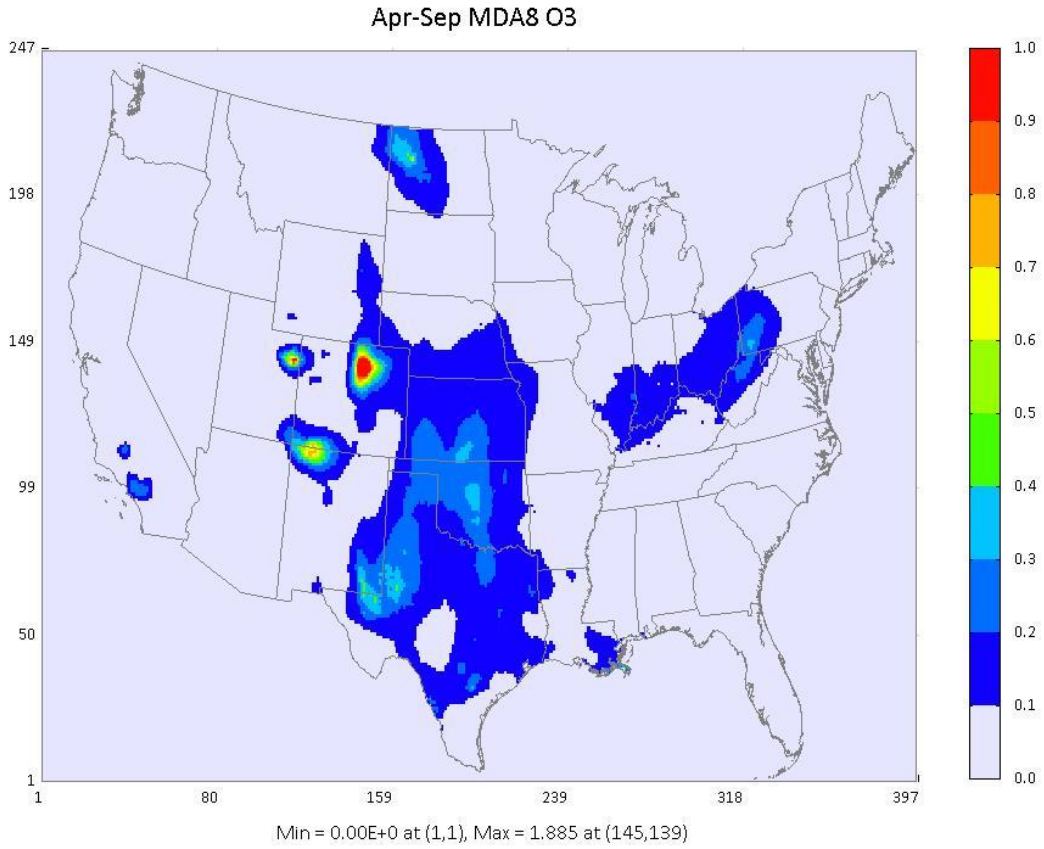

Figure A-4 **Contributions of 2017 Oil and Natural Gas VOC Emissions across the Contiguous U.S. to the April-September Average of MDA8 Ozone.**

Applying Modeling Outputs to Quantify a National VOC-Ozone Benefit Per-Ton Value

Following an approach detailed in the RIA and TSD for the Revised Cross-State Update, we estimated the number and value of ozone-attributable premature deaths and illnesses for the purposes of calculating a national ozone VOC benefit per-ton value for the proposed policy scenario (U.S. EPA, 2021f, 2021g).

The EPA historically has used evidence reported in the Integrated Science Assessment (ISA) for the most recent NAAQS review to inform its approach for quantifying air pollution-attributable health, welfare, and environmental impacts associated with that pollutant. The ISA synthesizes the toxicological, clinical and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either short-term (hours to less than one month) or long-term (one month to years) exposure; for each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship, or not likely to be a causal. We estimate the incidence of air pollution-attributable premature deaths and illnesses using methods reflecting evidence reported in the 2020 Ozone ISA (U.S. EPA, 2020a) and accounting for recommendations from the Science Advisory Board. When updating each health endpoint the EPA considered: (1) the extent to which there exists a causal relationship between that pollutant and the adverse effect; (2) whether suitable epidemiologic studies exist to support quantifying health impacts; (3) and whether robust economic approaches are available for estimating the value of the impact of reducing human exposure to the pollutant. Detailed descriptions of these updates are available in the TSD for the Final Revised Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Update titled Estimating PM2.5- and Ozone-Attributable Health Benefits (U.S. EPA, 2021h).

In brief, we used the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) to quantify estimated counts of premature deaths and illnesses attributable to summer season average ozone concentrations using the modeled surface described above (Section A.1.2). We calculate effects using a health impact function, which combines information regarding the: concentration-response relationship between air quality changes and the risk of a given adverse outcome; population exposed to the air quality change; baseline rate of death or disease in that population; and air pollution concentration to which the population is exposed. These quantified health impacts were then used to estimate the economic value of these ozone-attributable effects as described below. For this supplemental proposal, we quantified counts of premature deaths and illnesses by multiplying an incidence per ton against an updated estimate of emissions described in Section 2.3. Modeled air quality changes were not available.

We performed BenMAP-CE analyses for each year between 2024 and 2035, using the single model surface described above, but accounting for the change in population size, baseline death rates and income growth in each future year. We next divided the sum of the monetized ozone benefits in each year the April-September VOC emissions associated with the oil and natural gas source apportionment tags in the 2017 CAMx modeling to determine a benefit per ton value for each year from 2024–2035. Emissions totals for the oil and natural gas sector used in the contribution modeling are reported in U.S. EPA (2023). Finally, the benefit per ton values were multiplied by the expected national VOC emissions changes in each year, as reported in Section 2.3. Since values reported in Section 2 were annual totals, we assume the emissions changes are distributed evenly across months of the year and divide emissions changes by two to estimate the April-September VOC changes expected from this supplemental proposed rule.

Uncertainties and Limitations of Air Quality Methodology

The approach applied in this screening analysis is consistent with how air quality impacts have been estimated in past regulatory actions (U.S. EPA, 2019b, 2021f). However, in this section we acknowledge and discuss several limitations.

First, the 2017 modeled ozone concentrations are subject to uncertainty. While all models have some level of inherent uncertainty in their formulation and inputs, evaluation of the model outputs against ambient measurements shows that ozone model performance is within the range of model performance reported from photochemical modeling studies in the literature (Emery et al., 2017; Simon et al., 2012) and is adequate for estimating ozone impacts of VOC emissions for the purpose of this rulemaking.

In any complex analysis using estimated parameters and inputs from a variety of models, there are likely to be many sources of uncertainty. This analysis is no exception. This analysis includes many data sources as inputs, including emissions inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing benefits, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). Each of these inputs are uncertain and generate uncertainty in the benefits estimate. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits. Therefore, the estimates of annual benefits should be viewed as representative of the magnitude of benefits expected, rather than the actual benefits that would occur every year.

Because regulatory health impacts are distributed based on the degree to which housing and work locations overlap geographically with areas where atmospheric concentrations of pollutants change, it is difficult to fully know the distributional impacts of a rule. Air quality models provide some information on changes in air pollution concentrations induced by regulation, but it may be difficult to identify the characteristics of populations in those affected areas, as well as to perform high-resolution air quality modeling nationwide. Furthermore, the overall distribution of health benefits will depend on whether and how households engage in averting behaviors in response to changes in air quality, e.g., by moving or changing the amount of time spent outside (Sieg, Smith, Banzhaf, & Walsh, 2004).

Another limitation of the methodology is that it treats the response of ozone benefits to changes in emissions from the tagged sources as linear. For instance, the benefits associated with a 10 percent national change in oil and natural gas VOC emissions would be estimated to be twice as large as the benefits associated with a 5 percent change in nation oil and natural gas VOC emissions. The methodology therefore does not account for 1) any potential nonlinear responses of ozone atmospheric chemistry to emissions changes and 2) any departure from linearity that may occur in the estimated ozone-attributable health effects resulting from large changes in ozone exposures.

We note that the emissions changes are relatively small compared to 2017 emissions totals from all sources. Previous studies have shown that air pollutant concentrations generally respond linearly to small emissions changes of up to 30 percent (Cohan, Hakami, Hu, & Russell, 2005; Cohan & Napelenok, 2011; Dunker, Yarwood, Ortmann, & Wilson, 2002; Koo, Dunker, & Yarwood, 2007; Napelenok, Cohan, Hu, & Russell, 2006; Zavala, Lei, Molina, & Molina, 2009) and that linear scaling from source apportionment can do a reasonable job of representing impacts of 100 percent of emissions from individual sources (Baker & Kelly, 2014). Additionally, past studies have shown that ozone responds more linearly to changes in VOC emissions than changes in NO_X emissions (Hakami, Odman, & Russell, 2003; Hakami, Odman, & Russell, 2004). Therefore, it is reasonable to expect that the ozone benefits from expected VOC emissions changes from this proposed rule can be adequately represented using this this linear assumption.

A final limitation is that the source apportionment ozone contributions reflect the spatial and temporal distribution of the emissions from each source tag in the 2017 modeled case. The representation of the spatial patterns of ozone contributions are important because benefits calculations depend on the spatial patterns of ozone changes in relationship to spatial distribution of population and health incidence values. While we accounted for changes the size of the population, baseline rates of death and income, we assume the spatial pattern of oil and natural gas VOC contributions to ozone remain constant at 2017 levels. Thus, the current methodology does not allow us to represent any expected changes in the spatial patterns of ozone that could result from changes in oil and natural gas emissions patterns in future years or from spatially heterogeneous emissions changes resulting from this supplemental proposed rule. For instance, the method does not account for the possibility that new sources would change the spatial distribution of oil and natural gas VOC emissions.

Table A-2 Benefit-per-ton Estimates of Ozone-Attributable Premature Mortality and Illnesses for the WEC Proposal in 2019 Dollars

	Benefit-per-ton of Reducing VOC Emissions from the Oil and Natural Gas Sector			
	Short-term mortality and morbidity (discounted at 3%)	**Short-term mortality and morbidity (discounted at 7%)**	**Long-term mortality and morbidity (discounted at 3%)**	**Long-term mortality and morbidity (discounted at 7%)**
2025	$252	$225	$1,962	$1,753
2030	$272	$244	$2,183	$1,962
2035	$289	$260	$2,425	$2,172

Table A-3 Estimated Discounted Economic Value of Ozone-Attributable Premature Mortality and Illnesses under the Proposed WEC, 2024–2035 (million 2019$)[a,d]

	Proposed WEC	
Year	**3% Discount Rate**	**7% Discount Rate**
2024	$2.8[b] to $22[c]	$2.4[b] to $19[c]
2025	$5.4[b] to $42[c]	$4.5[b] to $35[c]
2026	$8.3[b] to $64[c]	$0.6.6[b] to $51[c]
2027	$0.080[b] to $0.62[c]	$0.061[b] to $0.48[c]
2028	$0.056[b] to $0.45[c]	$0.042[b] to $0.34[c]
2029	$0.055[b] to $0.44[c]	$0.039[b] to $0.31[c]
2030	$0.053[b] to $0.42[c]	$0.036[b] to $0.29[c]
2031	$0.051[b] to $0.41[c]	$0.034[b] to $0.27[c]
2032	$0.049[b] to $0.39[c]	$0.031[b] to $0.25[c]
2033	$0.050[b] to $0.42[c]	$0.031[b] to $0.26[c]
2034	$0.049[b] to $0.41[c]	$0.029[b] to $0.24[c]
2035	$0.047[b] to $0.39[c]	$0.027[b] to $ 0.22[c]

[a] Values rounded to two significant figures.

[b] Includes ozone mortality estimated using the pooled Katsouyanni et al. (2009) and Zanobetti and Schwartz (2008) short-term risk estimates.

[c] Includes ozone mortality estimated using the Turner et al. (2016) long-term risk estimate.

[d] The WEC regulates emissions of methane. Additional benefits to the regulation may result from associated reductions in VOC emissions.

Table A-4 Stream of Human Health Benefits under the Proposed WEC, 2024–2035: Monetized Benefits Quantified as Sum of Avoided Morbidity Health Effects and Avoided Long-term Ozone Mortality (discounted at 3 percent to 2023; million 2019$)[a,b]

Year	**Proposed WEC Option**
2024	$22
2025	$42
2026	$64
2027	$0.62
2028	$0.45
2029	$0.44
2030	$0.42
2031	$0.41
2032	$0.39
2033	$0.42
2034	$0.41
2035	$0.39
Present Value (PV)	**$139**
Equivalent Annualized Value (EAV)	**$13**

[a] Benefits calculation includes ozone-related morbidity effects and avoided ozone-attributable deaths quantified using the Turner et al. (2016) long-term risk estimate.

[b] The WEC regulates emissions of methane. Additional benefits to the regulation may result from associated reductions in VOC emissions.

Table A-5 Stream of Human Health Benefits under the Proposed WEC, 2024–2035: Monetized Benefits Quantified as Sum of Avoided Morbidity Health Effects and Avoided Long-term Ozone Mortality (discounted at 7 percent to 2023; million 2019$)[a,b]

Year	Proposed WEC Option
2024	$19
2025	$35
2026	$51
2027	$0.48
2028	$0.34
2029	$0.31
2030	$0.29
2031	$0.27
2032	$0.25
2033	$0.26
2034	$0.24
2035	$0.22
Present Value (PV)	**$108**
Equivalent Annualized Value (EAV)	**$14**

[a] Benefits calculated as value of avoided ozone-attributable deaths (quantified using a concentration-response relationship from the Turner et al. (2016) study and ozone-related morbidity effects).

[b] The WEC regulates emissions of methane. Additional benefits to the regulation may result from associated reductions in VOC emissions.

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APPLICATION OF THE FRAMEWORK FOR EVALUATING DAMAGES AND IMPACTS (FREDI) TO ASSESS THE DISTRIBUTION OF AVOIDED CLIMATE-DRIVEN DAMAGES

In this Appendix, we provide further detail on the distribution of climate-driven impacts avoided as a result of the methane (CH_4) emission reductions from the proposed WEC, using the Framework for Evaluating Damages and Impacts (FrEDI) (U.S. EPA, 2021a).

What is the Framework for Evaluating Damages and Impacts (FrEDI)?

The EPA developed FrEDI to better understand and communicate the detailed impacts and risks from climate change in the United States. FrEDI is a reduced complexity model that quantifies annual physical and economic impacts within contiguous U.S. borders through the end of the 21st century resulting from future climate change under any user-defined temperature trajectory. FrEDI draws upon over 30 existing peer-reviewed studies and climate change impact models, including from the Climate Change Impacts and Risk Analysis (CIRA) project[57], to estimate the relationship between future degrees of warming and damages across more than 20 impact sectors. FrEDI then uses these temperature-impact relationships to rapidly estimate climate change damages under any custom policy pathway. Recent FrEDI applications[58] have advanced the collective understanding of how future impacts from climate change are expected to be differentially experienced in different sectors across U.S. regions. The FrEDI framework and its Technical Documentation (U.S. EPA, 2021a) have been subject to a public review and an independent external peer review[59], following guidance in the EPA Peer-Review Handbook for

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[57] EPA Climate Change Impacts and Risk Analysis (CIRA). https://www.epa.gov/cira

[58] (1) Supplementary Material for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review”, Docket ID No. EPA-HQ-OAR-2021-0317 2022; (2) The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050. United States Department of State and the United States Executive Office of the President, Washington DC. 2021; (3) Climate Risk Exposure: An Assessment of the Federal Government’s Financial Risks to Climate Change, White Paper, Office of Management and budget, April 2022; (4) Hartin et al., Advancing the estimation of future climate impacts within the United States. EGUsphere, https://doi.org/10.5194/egusphere-2023-114.

[59] Information on the peer-review is available at the EPA Science Inventory: https://cfpub.epa.gov/si/si_public_record_report.cfm?dirEntryId=351316&Lab=OAP&simplesearch=0&showcriteria=2&sortby=pubDate&searchall=fredi&timstype=&datebeginpublishedpresented=02/14/2021.

Influential Scientific Information (ISI)[60]. FrEDI documentation and source code are available at: https://www.epa.gov/cira/fredi.

Why are Distributional Climate Impacts Important to Consider?

The impacts of climate change occuring in a particular area or to a particular community are determined by the physical climate stressors (e.g., heat, wildfire, flooding) unique to that location, the sensitivity to adverse effects, and the ability or capacity to adapt. This means that understanding the risks of climate change to the U.S., and the damages avoided due to greenhouse gas (GHG) emission reductions, is improved with detailed information regarding where impacts may occur, to what sectors, and how populations may be differentially affected. By leveraging the unique capabilities of FrEDI, EPA thereby offers additional context for this specific rulemaking to help the public better understand the environmental impacts and potential benefits from policies that reduce national GHG emissions, such as methane. The inclusion of the analysis also directly aligns with general recommendations from EPA's Science Advisory Board on a recent Agency rule[61]: "Given that exposure and vulnerability to climate risks vary, the benefits of reducing emissions vary as well. The differential benefits of reduced greenhouse gas emissions are not captured by the average social cost of carbon value and therefore additional consideration of the distributional effects of reducing greenhouse gas emissions is warranted. […] The EPA should utilize … the EPA CIRA program for information on the disproportionate health impacts of climate change and consider greenhouse gas implications from the proposed rule." By following these recommendations, the distributional application of FrEDI presented in the RIA complements, but does not replace, existing global climate impact and benefits assessments that use the social cost of greenhouse gases (SC-GHG). While global impacts from the proposed WEC are captured by the SC-GHG (in Chapter 6), FrEDI provides complementary illustrative information about how reductions in long-term climate-driven impacts may be differentially experienced within U.S. borders. Therefore, these results should not be compared to global SC-GHG estimates.

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[60] EPA Science and Technology Policy Council Peer Review Handbook. https://www.epa.gov/sites/default/files/2020-08/documents/epa_peer_review_handbook_4th_edition.pdf

[61] EPA Science Advisory Board Letter to Administrator Regan, Final Science Advisory Board Regulatory Review Report of Science Supporting EPA Decisions for the Proposed Rule: Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards (RIN 2060-AU41), EPA-SAB-23-001, December, 2022.

How is FrEDI Applied in the Proposed WEC RIA?

For this RIA, FrEDI is applied within a broader modeling workflow shown in Figure B-1 to analyze the distribution of avoided climate-driven impacts associated with proposed WEC CH_4 emission changes. While this application of FrEDI may be considered the most detailed and complete analysis of its kind, these estimates do not account for all damage categories, do not include damages outside U.S. borders (only those that can have implications on the U.S. economy), and do not consider damages that occur due to interactions between different sectors. Therefore, these estimates should be considered a preliminary accounting of net climate driven impacts relevant to U.S. interests.

Methodological Overview

Future global emission scenarios (Figure B-1, Input 1) are first passed to a climate emulator (model information provided in Section 4) to develop projections of global mean temperature (Figure B-1, Output 1). These mean temperature changes (Figure B-1, Input 2) are then passed to FrEDI[62], which quantifies the climate-driven damages in 22 sectors within U.S. borders that are associated with these temperature changes (Figure B-1, Output 2). In this analysis, the two global emission scenarios include: 1) a global time series of emissions with no additional mitigation (used to quantify projected baseline climate-driven damages) and 2) the same global baseline, with each year starting in 2024 (first year of the proposed WEC CH_4 reductions) adjusted for CH_4 emission changes resulting from the proposed WEC. Details and results are presented in the following sections.

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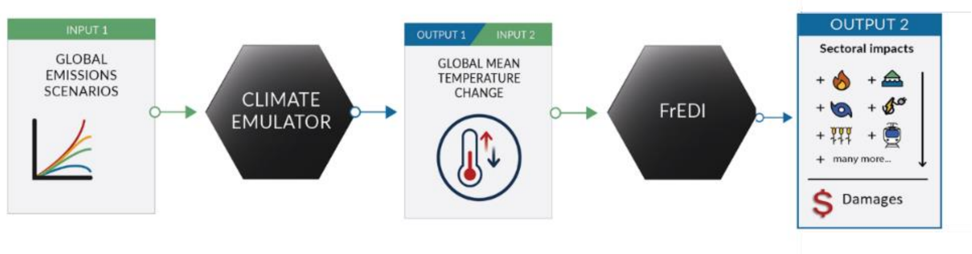
[62] https://github.com/USEPA/FrEDI/releases/tag/v3.4

Figure B-1 Schematic of Analysis Workflow from emissions to damages[63]



How are Avoided Climate Impacts Calculated?

This analysis presents the distribution of net avoided climate-driven impacts in the year 2090 that are associated with proposed WEC CH_4 emission reductions. Reductions of CH_4 emissions are taken from RIA Table 5-8, which presents the total annual CH_4 emission reductions from abatement activities associated with the proposed WEC (hereafter called the proposed WEC scenario). The avoided climate-driven impacts in 2090 are then calculated by comparing the distribution of long-term climate-driven damages across multiple populations, regions, and sectors in the proposed WEC scenario compared to the baseline scenario. The metric of annual net impacts captures both positive and negative impacts from climate change and is consistent with the approach used in the climate impacts literature, including the U.S. NCA (USGCRP, 2018) and IPCC (IPCC, 2022) assessments. Given the way that climate impacts accumulate over time, results here focus on the year 2090 to better capture the impacts from avoided long-term climate-driven changes[64]. Recognizing that "climate change creates new risks and exacerbates existing vulnerabilities in communities across the United States" (USGCRP, 2018), we use this approach to examine how the proposed WEC may mitigate projected monetized climate impacts across different regions, sectors, and populations.

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[63] Global emission scenarios (through 2100) are passed to the Finite amplitude Impulse Response (FaIR v1.6.4) climate emulator to develop global temperature projections associated with global emission changes. Global temperature changes are then passed to FrEDI, which applies sector and region-specific damage functions to project the domestic annual climate-driven damages across sectors associated with the emissions-driven global mean temperature changes.

[64] FrEDI is capable to quantifying impacts for any year through 2100. The snapshot of avoided impacts here represents the projected impacts in the year 2090 that are projected as a result of annual changes in emissions, each year, from the first policy year through 2090. This is a different approach than a net present damage analysis, which aggregates all impacts that result from a single emissions change in a particular year, through the year 2300.

Global Emissions Scenario

Global baseline emissions of greenhouse gases (GHGs) (CO_2, CH_4, N_2O, HFCs, PFCs), primary aerosol components (black carbon, organic carbon), pollutant precursors (CO, NO_x, SO_x, VOCs, NH_3), and other halogenated species (CFCs, CH_3Cl, CH_3Br, etc.) through the year 2100 are from the 'current policy scenario' developed by Ou et al., 2021. Projected temperature changes and climate-driven damages associated with these emissions represent projected damages in the absence of additional emissions mitigation policies.

Policy Emissions Scenario

To account for annual CH_4 emission reductions from abatement activities associated with the proposed WEC, the expected rule-specific reductions are subtracted from the global baseline emissions scenario (from Ou et al., 2021). In this analysis, reductions of CH_4 are held constant between the final emissions year and the year 2090. Results are minimally sensitive to this assumption. For all other compounds, emissions through the end of the century are taken from the global baseline scenario.

Climate Emulator & Projected Temperature Change

To convert global emissions to global temperature projections, we use the Finite amplitude Impulse Response (FaIR v1.6.4) climate emulator (Smith et al., 2018; Smith 2018), which captures the relationships between GHG emissions, atmospheric GHG concentrations, and global mean surface temperature. FaIR is a widely used reduced-complexity Earth system model recommended by the National Academies, calibrated to and extensively used within the Sixth Assessment Report (AR6) of the United Nations' Intergovernmental Panel on Climate Change (IPCC), and applied in EPA's November 2022 supplemental proposal for oil and gas standards (U.S. EPA, 2022). The mean results presented in this analysis are derived by running FaIR with an ensemble of 2237 sets of uncertain climate parameters[65] that have been previously calibrated to the IPCC AR6 Working Group 1 assessment (Smith, 2021).

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[65] Uncertainties in climate model parameters considered in FaIR, include but are not limited to the sensitivity of climate to increases in atmospheric CO_2 concentrations, forcing from aerosol components, forcing from black carbon on snow, and carbon cycle parameters.

Calculation of Avoided U.S. Climate-Driven Impacts

As described in the Technical Documentation (U.S. EPA, 2021a), FrEDI uses projections of global temperature and socioeconomic conditions (U.S. Gross Domestic Product [U.S. GDP] and regional population[66]) with underlying damage functions[67] to project economic damage end points for 22 impact sectors, listed in Table B-1.

While these sectors represent a large range of impacts across the U.S. economy, FrEDI does not include a comprehensive list of all impacts and only explores those that directly occur within contiguous U.S. borders. Therefore, FrEDI only provides a subset of the avoided climate impacts expected to accrue to U.S. citizens and their interests. In addition, not all anticipated impacts are quantified within the represented sectors – for example the coastal property analysis addresses direct flood damage to structures, but omits indirect impacts such as business interruptions that result from that damage. This approach also incorporates climate uncertainty from the FaIR model, but does not fully account for uncertainty in the underlying temperature-impact relationships for each sector. For a more detailed accounting of uncertainties, please see the FrEDI technical documentation (U.S. EPA, 2021a). Lastly, FrEDI also does not account for impacts of the proposed WEC resulting from factors outside of the direct impact of CH_4 emission reductions on climate change, such as direct air quality improvements from reductions in co-emissions of air pollutants.

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[66] Population scenarios are based on UN Median Population projection (United Nations, 2015) and EPA's ICLUSv2 model (Bierwagen et al., 2010; EPA 2017), and GDP from the EPPA version 6 model (Chen et al., 2015).

[67] A temperature binning approach is used to develop relationships between climate-driven changes in contiguous U.S. (CONUS) surface temperature or sea level rise (calculated from temperature), socioeconomic conditions (e.g., U.S. Gross Domestic Product [GDP] and regional population), and the resulting physical and economic damages across 22 sectors and seven CONUS regions. These temperature-impact relationships are synthesized from over 30 underlying peer-reviewed studies on climate change impact and form a key basis of FrEDI's calculations.

Table B-1 Current FrEDI sectors, including aggregate category group, default adaptation assumptions, and descriptions. Adapted from the FrEDI Technical Documentation

Sector	Aggregate Category	Default Adaptation or Variant Option	Impact Description
Agriculture	Agriculture	With CO_2 fertilization	Revenue lost from changes in wheat, cotton, soybean, and maize crop yields
Coastal Property	Infrastructure	Reactive Adaptation	Damage to coastal property value
Electricity Demand and Supply	Electricity	No Additional Adaptation*	Increases in power sector costs (e.g., capital, fuel, variable and fixed operations and maintenance cost
Electricity Transmission and Distribution	Electricity	Reactive Adaptation	Damages to transmission & distribution infrastructure
Temperature-Related Mortality	Health	No Additional Adaptation*	Mortality from changes in hot and cold temperatures
Transportation Impacts from High Tide Flooding	Infrastructure	Reasonably Anticipated Adaptation	Coastal flooding related traffic delays, rerouting, infrastructure improvements, and other transport impacts.
Inland Flooding	Infrastructure	No Additional Adaptation*	Residential damages from riverine flooding
Labor	Labor	No Additional Adaptation*	Damages from work hours lost in high-risk industries due to temperature
Marine Fisheries	Ecosystems + Recreation	No Additional Adaptation*	Changes in thermally available habitat for commercial fish species
Climate-Driven Air Quality Mortality	Health	2011 Precursor Emissions	Mortality from ozone and fine particulate matter exposure
Crime	Health	No Additional Adaptation*	Change in the number of Property and Violent crimes
Rail	Infrastructure	Reactive Adaptation	Infrastructure costs associated with temperature-induced track buckling
Roads	Infrastructure	Reactive Adaptation	Cost of road repair, user costs (vehicle damage), and road delays due to changes in road surface quality
Southwest Dust	Health	No Additional Adaptation*	Mortality from changes in fine and coarse dust particle exposure
Suicide	Health	No Additional Adaptation*	Impact of climate-driven changes in temperature and weather on suicide incidence
Wind Damage from Tropical Storms	Infrastructure	No Additional Adaptation*	Cost of changes in hurricane wind damage to coastal properties
Urban Drainage	Infrastructure	Proactive Adaptation	Costs of proactive urban drainage infrastructure adaptation
Water Quality	Ecosystems + Recreation	No Additional Adaptation*	Willingness to pay to avoid water quality changes
Wildfire	Health	No Additional Adaptation*	Mortality from wildfire emission exposure and response cost for fire suppression
Winter Recreation	Ecosystems + Recreation	Adaptation	Revenue lost from suppliers of alpine, cross-country skiing, and snowmobiling
Valley Fever	Health	No Additional Adaptation*	Mortality, morbidity, and lost wages
Vibriosis	Health	No Additional Adaptation*	Direct medical costs, lost days, and mortality from changes in Vibriosis cases

*'No additional adaptation' classification is sector specific and does not imply that there is no adaptation in the underlying study, only that there are no additional adaptation options in FrEDI. For more information please see the FrEDI technical documentation (U.S. EPA, 2021a).

Results: Distributional Changes in Avoided U.S. Climate-Driven Impacts

Results in this section represent the expected reduction in annual climate-driven impacts in 2090, or the economic impacts avoided, when implementing the proposed WEC CH_4 emission reductions (e.g., improvements = scenario #1 damages – scenario #2 damages)[68]. Considering the 22 sectors included in FrEDI, net avoided climate-driven damages from the proposed WEC at the national level are projected to occur across all sectors and regions within the contiguous United States. The majority of these improvements are projected to occur within sectors that are also projected to have the greatest baseline damages, including those that impact human health, such as reductions in mortality from temperature changes, mortality from climate-driven changes in air pollution (ozone and ambient fine particulate matter)[69], suicide incidence, exposure to wildfire smoke, Southwest dust, Vibriosis, and Valley fever, as well as reductions in lost labor hours and infrastructure-related impacts such as avoided transportation impacts from high-tide flooding, reduced property damage from hurricane winds, and avoided damages to roads and rail.

At the regional level, Figure B-2 provides a more detailed breakdown, by sector, of how changes in mean avoided climate-driven sectoral impacts are expected to vary across seven regions[70] within the contiguous U.S. by 2090. While all regions are expected to see reductions in net impacts under the proposed WEC scenario (column 1), that increase overtime (column 2), the right panel of Figure B-2 also lists the five sectors (of the 22 analyzed) that will accrue the largest annual reductions in impacts in each region. For example, while the largest improvements in all regions are projected to be from reduced mortality from avoided temperature changes, improvements related to air quality mortality (3rd largest sectors at the national level) are expected to be most pronounced in the Southwest, Southeast, and Northwest regions. In addition, avoided damages to transportation infrastructure (e.g., rail and roads) and agriculture are relatively more important in the Midwest and Northern Plains, while reduction in transportation impacts from high-tide flooding and avoided coastal property flood and wind

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[68] This metric differs from the net present benefits that are presented in RIA Chapter 6, which account for the discounted sum of climate-driven damages from the each WEC reduction year through 2300. Changes in annual impacts from FrEDI focus on 2090 to capture long-term climate-driven changes.

[69] The air quality impacts described here are a result of changes in concentrations of ozone and fine particulate matter ($PM_{2.5}$) that are the result of climate-driven changes in meteorology, atmospheric chemistry, and other biogeochemical factors. This is in contrast and in addition to the direct air quality changes resulting from changes in pollutant emissions from smokestacks, as discussed in other sections of this RIA.

[70] Corresponding to regions of the 4th U.S. National Climate Assessment.

damage are relatively more important in coastal regions. Lastly, relatively larger reductions in wildfire damages are projected in the Northwest, Southwest, and Northern Plains.

Figure B-2 Relative avoided per capita climate driven impacts by sector and US region.[71]

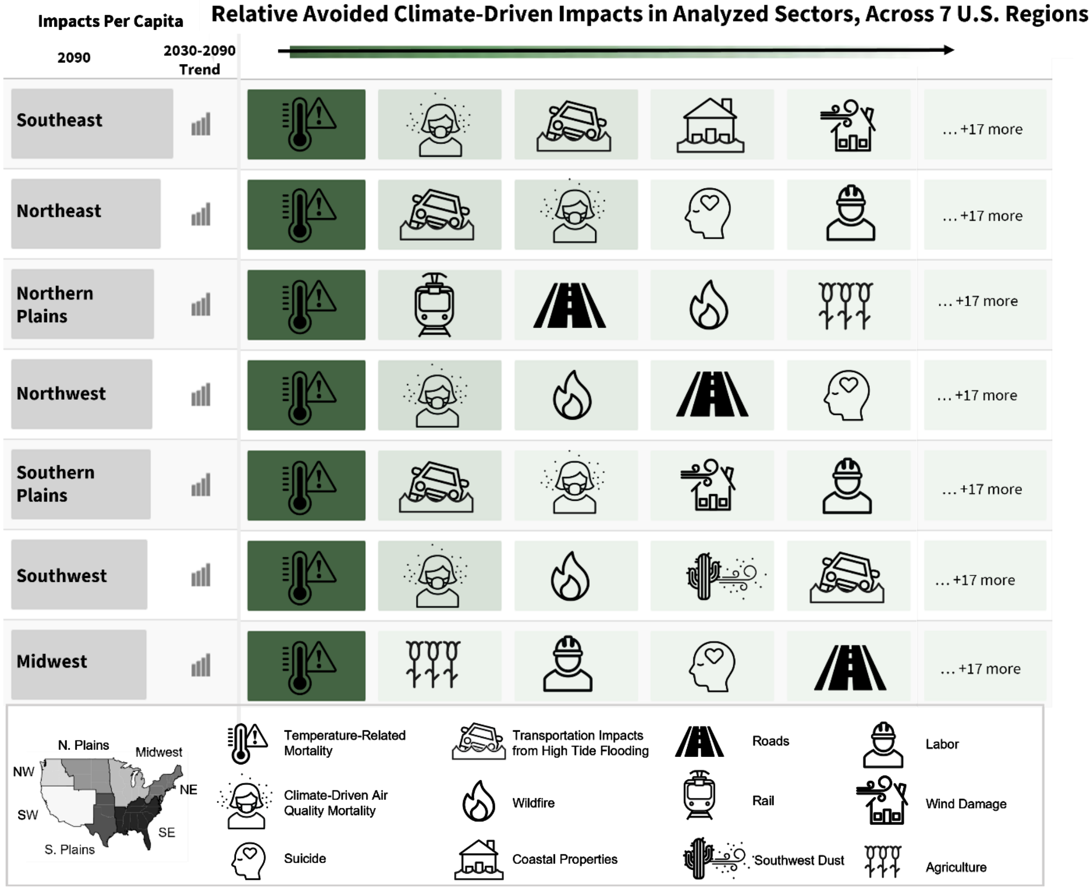

Figure B-3 provides a more detailed breakdown of the regional distribution across each sector and shows that for some sectors, reductions are only expected to occur in select regions, such as climate-driven changes in dust and Valley fever primarily impacting populations living in the Southwest, and reductions in tropical wind damage and transportation impacts from high-tide flooding largely occurring along coastlines of the Southeast, Southern Plains, and Northeast.

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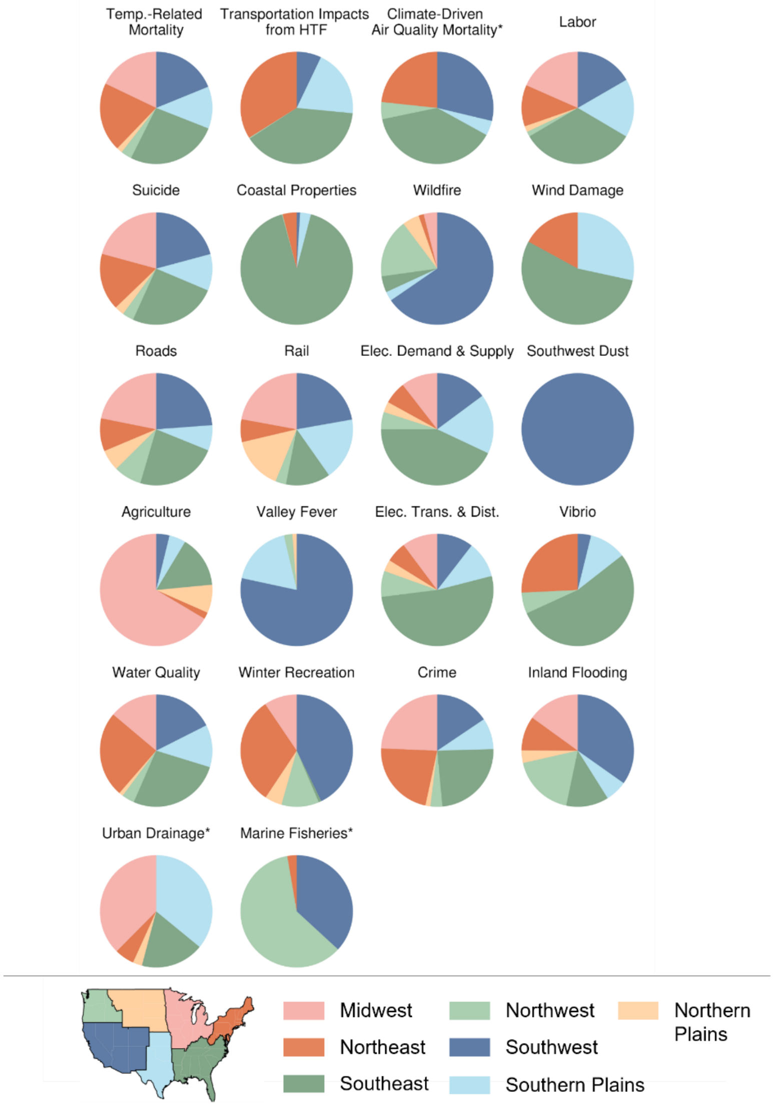
[71] Left bars) relative per capita improvements in each region in 2090 as well as the per capita improvements in the years 2030, 2050, 2070, and 2090. Right green tiles and icons) avoided climate–driven impacts experienced in each sector, in order of decreasing per capita impact changes (from left to right) in each region. Green shading illustrates the relative changes in each sector, normalized to the temperature mortality impacts in that region.

Figure B-3 Regional share of annual mean avoided U.S. climate-driven impacts in 2090[72]



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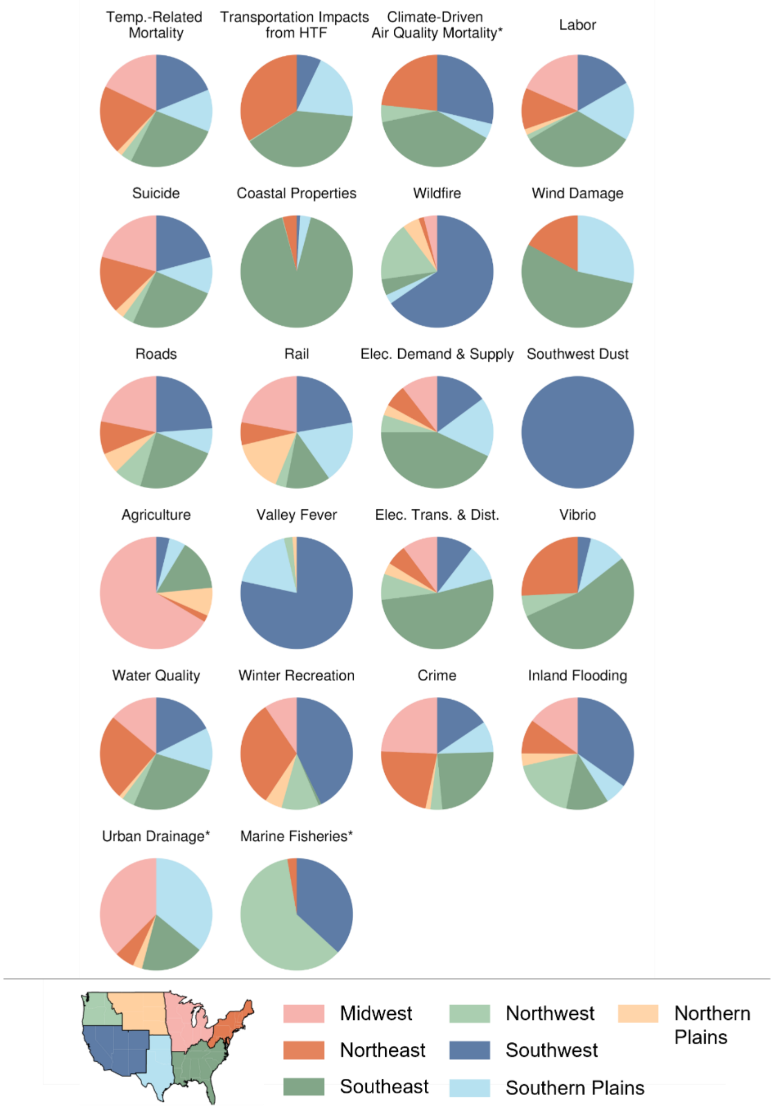
[72] Pie charts are ordered (left-to-right, top-to-bottom) by decreasing national impacts avoided within U.S. borders, such that premature mortality from temperature change has the largest and marine fisheries have the smallest. Sectors marked with an (*) have impacts increase in some regions, which are not shown in the pie charts.



Understanding the comparative risks to different populations living in different areas is also critical for developing effective and equitable strategies for responding to climate change. Analysis from a recent independently peer-reviewed EPA report on Climate Change and Social Vulnerability in the United States (U.S. EPA, 2021b) (hereafter referred to as the SV Report), provides a framework within FrEDI for better understanding the degree to which socially vulnerable populations are disproportionately exposed to the impacts from climate change in six impact categories.

As described in the SV Report, differential climate change risks are a function of exposure to where physical climate change impacts are projected to occur and vulnerability, in terms of an individual's capacity to prepare for, cope with, and recover from these impacts. This framework uses data on where populations live as an indicator of exposure and for vulnerability, considers four categories for which there is evidence of differential vulnerability (Table B-2), including low income (individuals living in households with income at or below 200% of the poverty level), ethnicity and race (individuals identifying as BIPOC[73]), educational attainment (individuals ages 25 and older with less than a high school diploma or equivalent), and age (individuals ages 65 and older). These categories are consistent with population groups of concern highlighted in EPA's Technical EJ Guidance U.S. EPA, 2016).

As described in the FrEDI Technical Documentation (Appendix G) (U.S. EPA, 2021a), differential impacts in each group are calculated in FrEDI at the Census tract level as a function of current population demographic patterns (i.e., percent of each group living in each census tract), projections of CONUS population (from ICLUS, U.S. EPA, 2017), and projections of where climate-driven impacts are projected to occur (i.e., using FrEDI temperature-impact relationships) at the Census tract level. The relative percent of each socially vulnerable group in each Census tract are from the 2014-2018 U.S. Census American Community Survey dataset (U.S. Census) and are held constant overtime because robust and long-term projections of local changes in demographics are not readily available.

Table B-2 Four socially vulnerable and reference groups considered here

Categories	Group Name	Description	Reference Group
Income	Low income	Individuals living in households with income that is 200% of the poverty level or lower	Individuals living in households with income greater than 200% of the poverty level.
Age	65 and Older	Ages 65 and older	Under age 65
Race and ethnicity	BIPOC	Individuals identifying as one or more of the following: Black or African American, American Indian or Alaska Native, Asian, Native Hawaiian or Other Pacific Islander, and/or Hispanic or Latino	Individuals identifying as White and/or non-Hispanic
Education	No High School Diploma	individuals aged 25 and older with less than a high school diploma or equivalent	Individuals aged 25 or older with educational attainment of a high school diploma (or equivalent) or higher.

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[73] This analysis uses the term BIPOC to refer to individuals identifying as Black or African American; American Indian or Alaska Native; Asian; Native Hawaiian or Other Pacific Islander; and/or Hispanic or Latino. It is acknowledged that there is no 'one size fits all' language when it comes to talking about race and ethnicity, and that no one term is going to be embraced by every member of a population or community. The use of BIPOC is intended to reinforce the fact that not all people of color have the same experience and cultural identity. This analysis therefore also includes results for individual racial and ethnic groups.

Figure B-4 shows how reductions in annual climate-driven impacts within the six impact categories[74], under the proposed WEC, are expected to be distributed across different populations, according to age, income, education level, and race and ethnicity. Those populations with greater than 100% differential improvements (right of the dashed lines) are projected to experience relatively larger reductions in long-term climate-driven impacts under the proposed WEC scenario, compared to their reference populations (Table B-2). These are the same populations that are projected to experience relatively larger damages under the baseline scenario. Those socially vulnerable groups with changes of less than 100% (left of the dashed lines) are still expected to see improvements but are projected to experience relatively smaller impact reductions than their reference populations. For example, Figure B-4 shows that BIPOC individuals age 65 and older are 13% more likely to see larger reductions in air quality attributable mortality relative to the white and/or non-Hispanic reference population. In addition, those in the low-income group are more likely (6%) to see larger reductions in lost labor hours than then those outside the low-income group. As nearly all bars in each category are to the right of the dashed lines, Figure B-4 also shows that nearly all socially vulnerable groups are projected to experience larger reductions in climate change impacts, compared to the reference populations.

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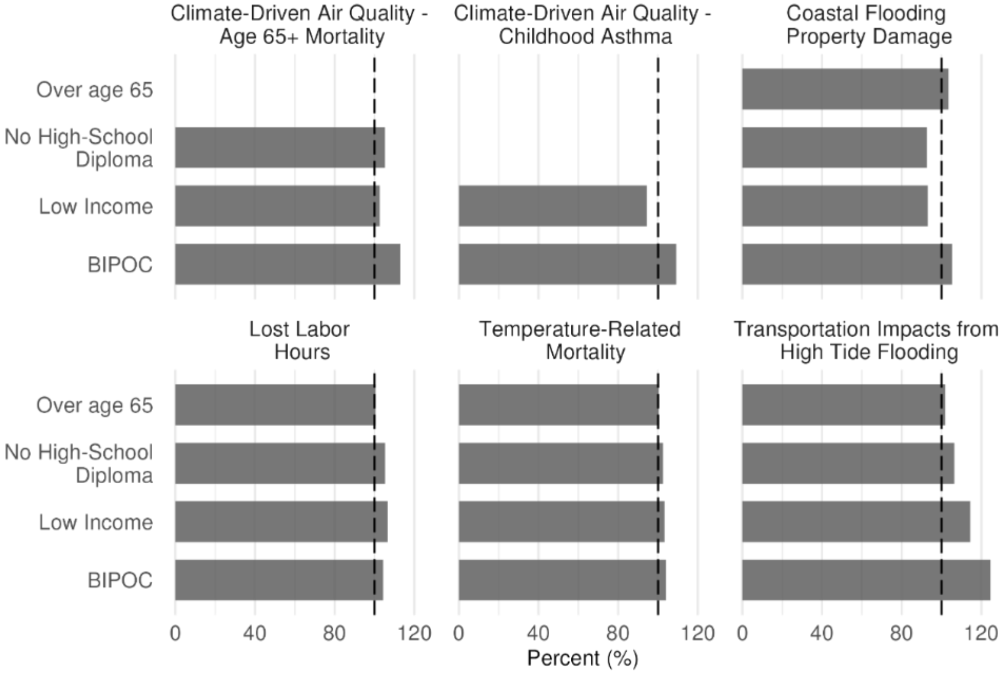
[74] The six impact categories include premature mortality (ages 65+) and new childhood (ages 0-17) asthma cases attributable climate-driven changes in air quality (ambient fine particulate matter), temperature mortality, labor hours lost due to high-temperature days, people impacted by coastal property inundation due to sea level rise, and transportation impacts from high tide flooding.

Figure B-4 Differential reductions in per capita climate-driven impacts in 2090 across socially vulnerable groups, normalized to the changes in their reference populations.[75]



Impacts to the BIPOC individuals in Figure B-4 can also be distributed across different races and ethnicities as shown in Figure B-5[76]. These are normalized to the per capita changes experienced by the national impacted population instead of a reference population. Therefore, bars to the right on the dashed lines in Figure B-5 indicate where specific groups of individuals will experience greater reductions in climate driven impacts compared to the national average and those to the left will experience smaller impact reductions than the national average.

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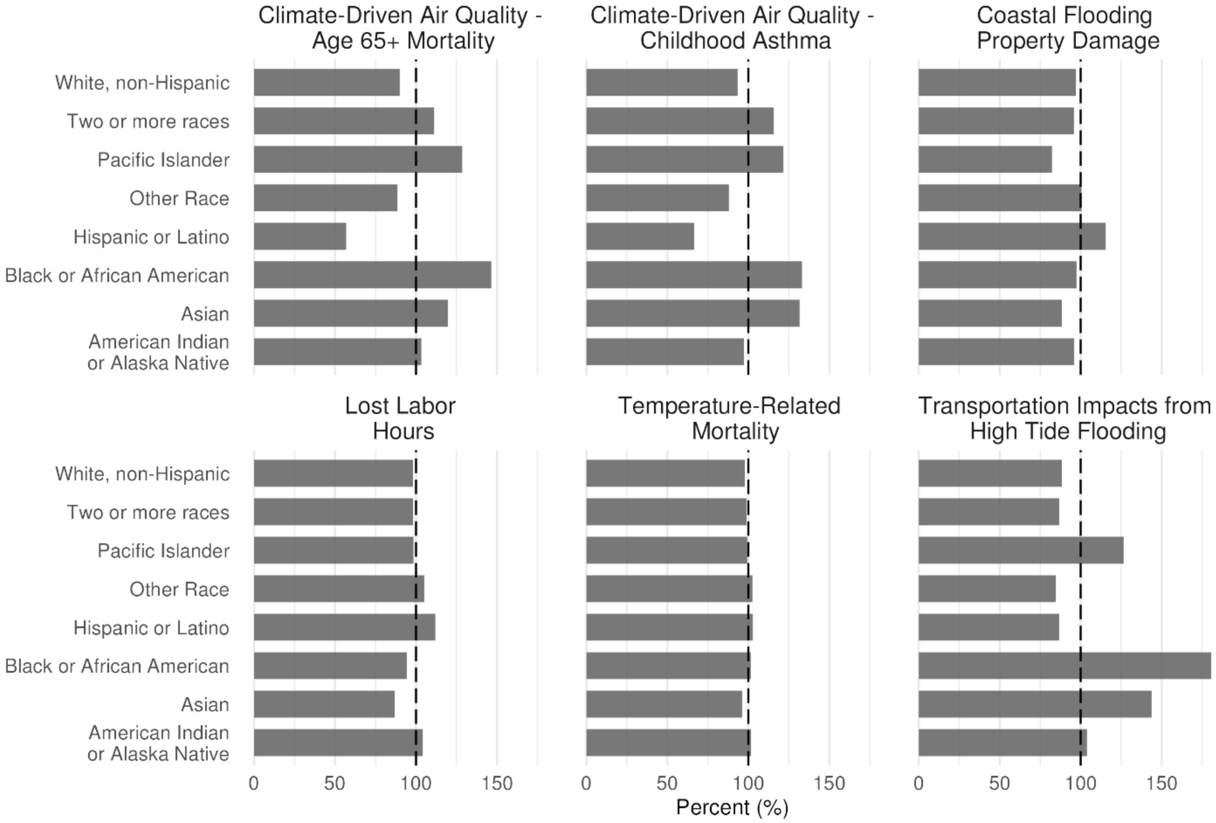
[75] Dashed gray lines represent 100% of the annual avoided impacts that are experienced by the reference population for that sector (Table C-2). Bars greater than 100% indicate that a group is projected to experience more impact reductions from proposed WEC reductions than the reference population. Bars less than 100% indicate that a group is projected to experience fewer impact reductions than the reference population. No bars indicate there are no impacts considered in that group. This is not a complete accounting of all climate impacts to the U.S.

[76] Impact results as a function of racial and ethnic group were also presented in EPA's SV Report.

Figure B-5 Per capita reductions in climate-driven impacts for six sectors in 2090, distributed by race and ethnicity.[77]



When considering current demographic patterns of different populations and the projected exposure to the six impact categories analyzed here, Figure B-5 shows that all groups are projected to see fewer climate change impacts under the proposed WEC scenario (all bars are greater than zero), but that some specific populations may see more benefits than others. For example, by 2090, Blacks and African Americans over the age of 65 are 46% more likely to see more reductions in climate-driven changes in air quality than the national average, which is largely because of regional differences in where these populations currently live and where future air quality changes are projected to occur. As another example, considering the effects of temperature on laborers working in exposed industries, Hispanics and Latinos are 12% more likely to see larger reductions in lost labor hours than the national average. Typically, the

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[77] Results for each sector are normalized to the average per capita impact avoided by the total impacted population in that sector. See Figure 4 caption for more details. This analysis does not consider effects on populations living in Hawai'i, Alaska, or U.S. territories but does use demographic data from the U.S. Census which includes individuals living in the contiguous U.S. who identify as "American Indian or Alaska Native" and "Native Hawaiian or Other Pacific Islander."

populations projected to be impacted the most by climate change under the baseline scenario are the same groups that will experience the greatest reductions in impacts under the proposed WEC.

There are many impacts of climate change and additional dimensions of vulnerability that are not incorporated into this analysis, and therefore these results only reveal a portion of the potential unequal risks to socially vulnerable populations. In addition, this analysis does not consider how changes in future demographic patterns in the U.S. could affect risks to these populations, nor how climate change may affect socially vulnerable populations living outside the contiguous United States.

Overall, the FrEDI analyses presented here is intended to produce estimates of annual net climate-driven impacts within U.S. borders using the best available data and methods. FrEDI was developed using a transparent process, peer-reviewed methodologies, and is designed as a flexible framework that is continually refined to reflect the current state of climate change impact science. While FrEDI does not provide a complete and comprehensive accounting of all potential climate change impacts relevant to U.S. interests, and is subject to uncertainties (such as future levels of adaptation), this analysis provides the most detailed and complete illustration to date of the distribution of climate change impacts within U.S. borders.

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ADDITIONAL INFORMATION ON MARGINAL ABATEMENT COST (MAC) MODELING FOR ANALYSIS OF WASTE EMISSIONS CHARGE

MAC Model Overview

Marginal abatement cost (MAC) model is a bottom-up, engineering cost analysis using the most current information on mitigation options available to the United States oil and gas industry. The modeling approach and many of the key assumptions are consistent with the methodology described in the EPA's *Global Non-CO_2 Greenhouse Gas Emission Projections & Mitigation, 2015–2050 report*. The MAC curve is constructed by estimating the carbon price at which the present-value benefits and costs for each mitigation option equilibrate. The methodology produces a stepwise curve, where each point reflects the average price and reduction potential if a mitigation technology were applied across the sector. In conjunction with the projected GHG emissions for from facilities subject to the WEC, we express the resulting annual reductions in metric tons of methane (tCH_4).

MAC Model Description

The MAC model considers a suite of mitigation technologies applicable to facilities subject to the WEC. Each mitigation technology is characterized with respect to variables related to technical effectiveness in reducing emissions and cost for the purpose of calculating a breakeven price. The MACC is constructed by aggregating mitigation potential from all technologies as applied to the emissions baseline.

Mitigation Technology Emissions Reduction Characteristics

The mitigation potential associated with each mitigation is based on a number of factors that include technical applicability, market penetration, and reduction efficiency. The technical effectiveness of each mitigation option is calculated as shown in Table C-1.

Table C-1 Calculation of Emission Reductions for a Mitigation Option

Technical Applicability (%)	**X**	**Market Share[a] (%)**	**X**	**Reduction Efficiency (%)**	**=**	**Technical Effectiveness (%)**				
						Technical Effectiveness (%)	X	Baseline Emissions (tCH_4)	=	Emissions Reductions (tCH_4)
Percentage of total baseline emissions from a particular emission source to which a given option can be potentially applied.		Percentage of technically applicable baseline emissions to which a given option is applied; avoids double counting among competing options.		Percentage of technically achievable emission mitigation for an option after it is applied to a given emission stream.		Percentage of baseline emissions that can be reduced at the national or regional level by a given option.		Emission stream to which the option is applied.		Unit emission reductions.

[a] Implied market shares for noncompeting mitigation options (i.e., only one option is applicable for an emission streams) sums to 100%.

where:

$TA =$ technical applicability (%)
$MS =$ market share (%)
$RE =$ reduction efficiency (%)
$TE =$ technical efficiency (%)
$BE =$ baseline emissions (tCH_4)

Technical applicability accounts for the portion of emissions from a facility or region that a mitigation option could feasibly reduce based on its application. For example, if an option applies only to the underground portion of emissions from coal mining, then the technical applicability for the option would be the percentage of emissions from underground mining relative to total emissions from coal mining.

The implied market share of an option is a mathematical adjustment for other qualitative factors that may influence the effectiveness or adoption of a mitigation option. We used market shares for each mitigation option within every sector. The market shares, determined by various sector-specific methods, must sum to one for each sector and were assumed constant over time. This assumption avoids cumulative reductions of greater than 100% across options.

When nonoverlapping options are applied, they affect 100% of baseline emissions from the relevant source. Examples of two nonoverlapping options in the natural gas system are replacement of high-bleed pneumatic devices and leak detection and repair of compressors in the transmission segment. These options were applied independently to different parts of the sector and do not compete for the same emission stream.

The reduction efficiency of a mitigation option is the percentage reduction achieved with adoption. The reduction efficiency was applied to the relevant baseline emissions as defined by technical applicability and adoption effectiveness. Most abatement options, when adopted, reduce an emission stream less than 100%. If multiple options are available for the same component, the total reduction for that component is less than 100%.

Once the technical effectiveness of an option was calculated as described above, this percentage was multiplied by the baseline emissions for each sector and region to calculate the absolute amount of emissions reduced by employing the option. The absolute amount of baseline emissions reduced by an option in a given year is expressed in metric tons of methane.

If the options were assumed to be technically feasible in a given region, they were assumed to be implemented immediately. Furthermore, once options are adopted, they were assumed to remain in place for the duration of the analysis, and an option's parameters do not change over its lifetime.

Mitigation Technology Economic Characteristics

Each abatement option is characterized in terms of its costs and benefits per abated unit of gas (tons of emitted CH_4). The carbon price at which an option's benefits equal the costs is referred to as the option's break-even price.

For each mitigation option, the carbon price (P) at which that option becomes economically viable was calculated using the equation below (i.e., where the present value of the benefits of the option equals the present value of the costs of implementing the option). A present value analysis of each option was used to determine break-even mitigation costs. Break-even calculations are independent of the year the mitigation option is implemented but are contingent on the life expectancy of the option. The net present value calculation solves for break-even price *P* by equating the present value of the benefits with the present value of the costs of the mitigation option. More specifically,

$$\underbrace{\sum_{t=1}^{T}\left[\frac{(1-TR)(P\cdot ER+R)+TB}{(1+DR)^{t}}\right]}_{\textit{Net Present Benefits}}=\underbrace{CC+\sum_{t=1}^{T}\left[\frac{(1-TR)RC}{(1+DR)^{t}}\right]}_{\textit{Net Present Costs}} \tag{D.1}$$

where:

P = the break-even price of the option ($/tCH4)
ER = the emission reduction achieved by the technology (tCH4)
R = the revenue generated from energy production (scaled based energy prices)
T = the option lifetime (years)
DR = the discount rate (5%)
CC = the one-time capital cost of the option ($)
RC = the recurring (O&M) cost of the option (portions of which may be scaled based on regional labor and materials costs) ($/year)
TR = the tax rate (0%)

Assuming that the emission reduction *ER*, the recurring costs *RC*, and the revenue *R* do not change on an annual basis, then we can rearrange this equation to solve for the break-even price P of the option for a given year:

$$P=\frac{CC}{(1-TR)\cdot ER\cdot\sum_{t=1}^{T}\frac{1}{(1+DR)^{t}}}+\frac{RC}{ER}-\frac{R}{ER}-\frac{CC}{ER\cdot T}\cdot\frac{TR}{(1-TR)} \tag{D.2}$$

Costs include capital or one-time costs and O&M or recurring costs. Most of the agricultural sector options, such as changes in management practices, do not have applicable capital costs, with the exception of anaerobic digesters for manure management.

Benefits or revenues from employing an abatement option can include (1) the intrinsic value of the recovered gas (e.g., the value of CH4 either as natural gas or as electricity/heat), (2) non-GHG benefits of abatement options (e.g., non-energy savings for labor or equipment). In most cases, the abatement of CH_4 has two price signals: one price based on CH_4's value as energy (because natural gas is between 90% and 98% CH_4) and one price based on CH_4's value as a GHG. All cost and benefit values are expressed in constant-year 2019 dollars. The analysis applied a 5% discount rate and assumed a 0% tax rate. Table C-2 lists the basic financial assumptions used in the analysis.

Table C-2 Financial Assumptions in Break-Even Price Calculation for Mitigation Options

Economic Parameter	Assumption
Discount rate	5%
Tax rate	0%
Constant-year dollars	2019$

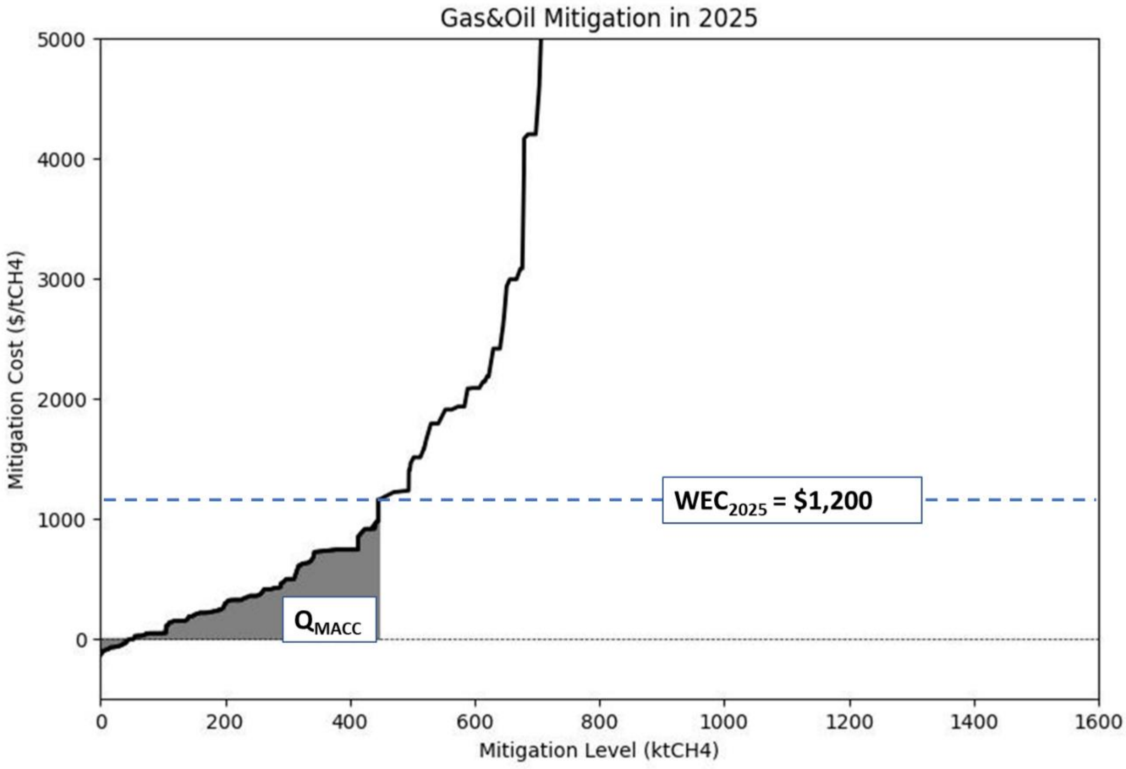
Finally, the MACC model also includes assumptions regarding the quantitative impacts of learning over time. The results of learning overtime reduce the costs of implement the mitigation measures while also improving the reduction efficiency of mitigation measures over time. This element of the MACC model means costs of mitigation in future years will be lower compared to the present. As a result, some mitigation measures not cost-effective in 2024 ($\$/tCH_4 <= WEC\ \$/tCH_4$) may be costs-effective in later years.

WEC Facility MAC Curves Construction

The mitigation option analysis throughout this report was conducted using a common methodology and framework. MAC curves were constructed for each region and sector by estimating the "break-even" price at which the present-value benefits and costs for each mitigation option equilibrate. The methodology produces a curve where each point reflects the average price and reduction potential if a mitigation technology were systematically adopted by all similar facilities across the oil or gas segment. When combined with the projected baseline emissions for the specific facility type, results are expressed in absolute annual reductions (tCH4) at specific average mitigation costs or prices. For example, in the illustrative MAC shown in Figure C-1 below shows the quantity of mitigation technical achievable at prices below the WEC rate ($/tCH4). The quantity of mitigation (Q_macc) expected from WEC facilities in the 2025 is ~460 ktCH4, where the MAC curve crosses the WEC.

The Q_MACC represents the full technically available mitigation potential at mitigations costs below the WEC charge. In order to account for practical limitations in the speed of deploying cost-effective mitigation to oil and gas operations, the analysis assumed a three-year phase-in period for reductions over 2024 to 2026. The phase-in parameter constrains the mitigation potential in 2024 and 2025 to 33% and 67% of total mitigation potential to simulate the assumption that it will take facilities several years to fully implement mitigation measures. Depending upon a variety of factors, potential technology deployment speed may be faster or slower than this assumption. Because many of the mitigation technologies estimated in the MACC model correspond to mitigation technologies considered as part of the NSPS OOOOb/EG OOOOc rulemaking process, oil and gas operators have been aware of potential requirements since 2021. However, widespread deployment of mitigation technologies may be affected by supply chain, labor, or other constraints that could prevent full utilization in the short term.

Figure C-1 Illustrative MAC Curve for Facilities with Emissions Subject to the WEC in the year 2025



Mitigation Options Modeled

This mitigation analysis utilized information on mitigation measures cost and performance gathered as part of technology analysis process from the Oil and Natural Gas NSPS OOOOb and EG OOOOc rulemaking process. Data on technologies was derived from both the analysis related to the 2021 proposal and the 2022 supplemental proposal. In particular, updated technology cost and performance data was drawn from spreadsheets published in the docket underlying the NSPS OOOOb and EG OOOOc Technical Support Documents (EPA, 2022 and 2021). Mitigation option information address methane emissions from the following emissions sources:

Table C-3 lists the mitigation technologies included in the MACC analysis for the WEC rule.

Table C-3 Mitigation Technologies Included in WEC Analysis by Source Category

Emissions Source	Mitigation Options
Pneumatic controllers	• Replace Continuous High-Bleed Controllers with Low-Bleed Controllers • Electric Powered Controllers (where a grid connection, on-site power exists) • Solar Powered Electronic Controllers
Fugitive emissions from well sites	• Fugitive Emissions Leak Detection and Repair at Well Sites
Fugitive emissions from natural gas processing plants	• Fugitive Emissions Leak Detection and Repair at NG Processing Plants
Fugitive emissions from compressor stations	• Fugitive Emissions Leak Detection and Repair at compressor stations
Fugitive emissions from offshore facilities	• Fugitive Emissions Leak Detection and Repair at offshore facilities
Pneumatic pumps	• Install a New Combustion Device or Process • Route Emissions to an Existing Combustion Device or Process • Replace a gas-driven pump with an electric pump – Processing
Liquids Unloading	• Non-Venting Liquids Unloading Techniques
Reciprocating compressors	• Replacement of rod packing every 3 years • Fugitive Emissions Leak Detection and Repair • Routing of Emission Through a Closed Vent System Under Negative Pressure to a Combustion Device
Centrifugal compressors	• Converting Wet Seals to Dry Seals System • Routing emissions to a New Control Device • Routing emissions to an Enclosed Combustion Device or Process.

The balance of this section briefly defines the sources and mitigation technologies considered for the WEC analysis. Much of the definitions are terms are borrowed directly from the EPA 2021 Background Technical Support Document for the NSPS OOOOb and EG OOOOc analysis of the Oil and Natural Gas Sectors (EPA,2021).

Pneumatic Controllers

Pneumatic controllers are devices used to regulate a variety of physical parameters, or process variables, using air or gas pressure to control the operation of mechanical devices, such as valves. The valve control process conditions such as levels, temperatures and pressures. When a pneumatic controller identifies the need to alter a process condition, it will open or close a control valve. In many situations across all segments of the oil and natural gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control the valve. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control.

Pneumatic controllers can be categorized based on the emissions pattern of the controller. Some controllers are designed to have the supply-gas provide the required pressure to power the end-device, and the excess amount of gas is emitted. The emissions of this excess gas are referred to as "bleed," and this bleed occurs continuously. Also referred to as "continuous bleed" pneumatic controllers, these controllers can be further categorized based on the bleed volume. Controllers with bleed rate less than or equal to 6 standard cubic feet per hour (scfh) are referred to as "low bleed," and those with a higher bleed rate are referred to as "high bleed." Another type of controller is designed to release gas only when the process parameter needs to be adjusted by opening or closing the valve, and there is no vent or bleed of gas to the atmosphere when the valve is stationary. These types of controllers are referred to as "intermittent vent" pneumatic controllers. EPA (2021) cites that while emissions from individual pneumatic controllers are small, there are an estimated 1.7 million controllers utilized across oil and gas production facilities and natural gas transmission and storage facilities. Combined emissions from all these pneumatic controllers represents approximately 50% of the baseline emissions from WEC applicable facilities.

Emissions from natural gas-powered pneumatic controllers occur as a function of their design. Continuous bleed controllers using natural gas as the power source emit a portion of that gas at a constant rate. Intermittent vent controllers using natural gas as the power source emit natural gas only when the controller sends a signal to open or close the valve.

The mitigation options for pneumatic controllers are summarized below these include: (1) replacing high-bleed controllers with low-bleed controllers; (2) electric powered controllers; and

(3) solar powered controller systems. Additionally, the analysis categorizes facilities based on the controller site type (new vs. existing) and facility size (large, medium, and small), these site configurations were assumed to change over from existing to new sites over a 15-year time frame.

Under the baseline projections developed for this analysis there are no emissions from the new facility in the baseline in 2021. All the CH_4 distribution are from existing facilities.

Zero Emissions Options in Production, Gathering and Boosting, Transmission Compression, and Underground Natural Gas Storage

Low-bleed controllers provide the same operational function as high-bleed controllers but have lower continuous bleed emissions. This analysis adopts the technology costs assumptions presented in EPA, 2022. The technical lifetime of equipment was assumed to be 15 years. The reduction efficiency is assumed to be 100% for all zero emissions mitigation options. Table C-4 below summarizes the reduction efficiency and costs by pneumatic controller type.

Table C-4 Technology and Cost Inputs by Model Facility Size and Type for Zero Emissions Options in Production; Gathering and Boosting; Transmission and Storage

Facility Size	Site Type	Mitigation Option	Reduction Efficiency	Capital Costs ($2019)	O&M Costs ($2019)
Small	New	Electric controllers -grid	100%	$15,287	-$916
Small	New	Electric controllers - solar	100%	$16,831	-$726
Small	New	Compressed air - grid	100%	$47,512	$4,068
Small	New	Compressed air - generator	100%	$95,115	$2,161
Medium	New	Electric controllers -grid	100%	$25,426	-$1,832
Medium	New	Electric controllers - solar	100%	$28,515	-$1,452
Medium	New	Compressed air - grid	100%	$71,426	$2,816
Medium	New	Compressed air - generator	100%	$100,231	$909
Large	New	Electric controllers -grid	100%	$55,842	-$4,582
Large	New	Electric controllers - solar	100%	$63,049	-$3,665
Large	New	Compressed air - grid	100%	$113,277	$2,454
Large	New	Compressed air - generator	100%	$190,577	-$1,360
Small	Existing	Electric controllers -grid	100%	$20,593	-$916
Small	Existing	Electric controllers - solar	100%	$22,653	-$726
Small	Existing	Compressed air - grid	100%	$58,636	$4,068
Small	Existing	Compressed air - generator	100%	$120,000	$2,161
Medium	Existing	Electric controllers -grid	100%	$34,322	-$1,832
Medium	Existing	Electric controllers - solar	100%	$38,441	-$1,452
Medium	Existing	Compressed air - grid	100%	$76,481	$2,816
Medium	Existing	Compressed air - generator	100%	$120,000	$909
Large	Existing	Electric controllers -grid	100%	$75,508	-$4,582
Large	Existing	Electric controllers - solar	100%	$85,119	-$3,665
Large	Existing	Compressed air - grid	100%	$127,469	$2,454
Large	Existing	Compressed air - generator	100%	$220,000	-$1,360

Options If Zero-Emission Options are Technically Infeasible

As described in EPA, 2022, the primary costs associated with electronic controller systems are the initial capital expenditures for the equipment (i.e., controllers and control panel), the engineering and installation costs, and the operating costs for electrical energy. Electrical supply is assumed to be available at the facility irrespective of the electronic controllers at the site, the costs of the power supply were not included in the mitigation option costs for electronic controllers. Table C-5 presents the costs for electronic controllers across production, transmission and storage segments at facilities based on the number of controllers at each site. The technical lifetime of equipment was assumed to be 15 years.

Table C-5 Technology and Cost Inputs by Model Facility Size and Type Zero Emissions Options in Production; Gathering and Boosting; Transmission and Storage

Facility Size	Site Type	Mitigation Option	Reduction Efficiency	Capital Costs ($2019)	O&M Costs ($2019)
Small	New	Route to existing combustion device	95.0%	$15,256	$497
Small	New	Route to new combustion device	95.0%	$53,725	$20,846
Small	New	Install low or intermittent controllers with inspection	27.3%	$0	$600
Medium	New	Route to existing combustion device	95.0%	$27,461	$1,329
Medium	New	Route to new combustion device	95.0%	$65,930	$21,244
Medium	New	Install low or intermittent controllers with inspection	38.4%	$0	$600
Large	New	Route to existing combustion device	95.0%	$64,075	$2,088
Large	New	Route to new combustion device	95.0%	$102,544	$22,437
Large	New	Install low or intermittent controllers with inspection	38.4%	$0	$600
Small	Existing	Route to existing combustion device	95.0%	$15,256	$497
Small	Existing	Route to new combustion device	95.0%	$53,725	$20,846
Small	Existing	Install low or intermittent controllers with inspection	27.3%	$0	$600
Medium	Existing	Route to existing combustion device	95.0%	$27,461	$1,329
Medium	Existing	Route to new combustion device	95.0%	$65,930	$21,244
Medium	Existing	Install low or intermittent controllers with inspection	38.4%	$0	$600
Large	Existing	Route to existing combustion device	95.0%	$64,075	$2,088
Large	Existing	Route to new combustion device	95.0%	$102,544	$22,437

Large	Existing	Install low or intermittent controllers with inspection*	38.4%	$0	$600

Fugitive Emissions from Well Sites, Gas Processing Plants, Compressor Stations and Offshore Facilities

There are several potential sources of fugitive emissions throughout the oil and natural gas industry. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated pressure relief valves (PRVs) or worn gaskets on thief hatches on controlled storage vessels are also potential causes of fugitive emissions. Additional sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves or controlled liquid storage tanks. EPA 2022 analysis provided a breakdown of model facilities for the production well sites categorized by the types of equipment in operation at the site.

Table C-6 below presents the reduction efficiency and costs for the various mitigation options models to address fugitive emissions across the segments of the oil and natural gas industry. For production wellhead sites this analysis simplified the number of options to only include the options that assumed 0.5% leak rates. For offshore production facilities this analysis applies the directed inspection and maintenance option reported in EPA 2019, as there was no clear updated cost information for this type of facility in earlier cited NSPS OOOOb/EG OOOOc analysis.

Table C-6 Technology and Cost Inputs by Mitigation Option in Production; Gathering and Boosting; Transmission and Storage

Segment	Site Type	Mitigation Option	Reduction Efficiency	Capital Costs ($2019)	O&M Costs ($2019)
Production	Single Wellhead Only	Equipment Leak Monitoring at Well Site (0.5% leak rate, 30 day repair) [a]	48%	1,027	1,889
Production	Wellhead, tank, and other	Equipment Leak Monitoring at Well Site (0.5% leak rate, 30 day repair) [a]	47%	1,027	2,160
Production	Multi-Wellhead Only	Equipment Leak Monitoring at Well Site (0.5% leak rate, 30 day repair) [a]	44%	1,027	1,858
Production	Offshore	Direct Inspection & Maintenance [c]	95%	-	33,333
G&B	Compressor Station	Equipment Leak Monitoring Program at a Compressor Station (G&B) w/o Recovery Credits [b]	43%	1,027	10,134
Processing	Processing Plant	Equipment Leak Monitoring Program at Processing Plant [b]	40%	3,087	6,353
Transmission	Compressor Station	Equipment Leak Monitoring Program at a Compressor Station (Transmission) w/o Recovery Credits [b]	40%	23,883	12,903
Storage	Compressor Station	Equipment Leak Monitoring Program at a Compressor Station (Storage) w/o Recovery Credits [b]	40%	23,883	17,000

Source: a)EPA, 2022; b) EPA, 2021, and c) EPA, 2019.

Pneumatic Pumps

A pneumatic pump is a positive displacement reciprocating unit generally used by the Oil and Natural Gas Industry for one of four purposes: (1) hot oil circulation for heat tracing/freeze protection, (2) chemical injection, (3) moving bulk liquids, and (4) glycol circulation in dehydrators. There are two basic types of pneumatic pumps used in the Oil and Natural Gas Industry -- diaphragm pumps and piston pumps. Natural gas-driven pneumatic pumps emit methane and volatile organic compounds (VOC) as part of their normal operation. However, pneumatic pumps may also be powered by electricity or compressed air, and these types of controllers do not use or emit natural gas.

Two types of control options were evaluated in the revised technology analysis related to the 2022 Supplemental proposal (EPA, 2022). The first type utilizes pneumatic pumps that are not driven by natural gas, thus eliminating methane emissions. The other option is to reduce emissions when natural gas-driven pneumatic pumps are used. Table C-7 summarizes the base mitigation technology and cost assumptions for pneumatic pumps. These options are applied across to emissions from production and G&B, transmission, and storage segments.

Table C-7 Technology and Cost Inputs by Mitigation Option in Production; Gathering and Boosting; Transmission and Storage

Pump Type	Mitigation Option	Reduction Efficiency	Capital Costs ($2019)	O&M Costs ($2019)
Zero Emissions (Non NG-Driven)				
One Diaphragm	Electric Pump	100%	$5,219	$329
One Diaphragm	Solar Powered Electric Pump	100%	$2,246	$0
One Diaphragm	Compressed Air-Driven Pump	100%	$6,742	$10,335
One Piston	Electric Pump	100%	$2,043	$329
One Piston	Solar Powered Electric Pump	100%	$2,246	$0
One Piston	Compressed Air-Driven Pump	100%	$6,742	$0
Routing to Combustion if Zero Emissions is Technically Infeasible				
One Diaphragm	Route Emissions to an Existing Process	95%	$6,102	$0
One Piston	Route Emissions to an Existing Process	95%	$6,102	$0
One Diaphragm	Route Emissions to an Existing Combustion Device	95%	$6,102	$0
One Piston	Route Emissions to an Existing Combustion Device	95%	$6,102	$0
One Diaphragm	Route Emissions to a New Combustion Device	95%	$38,469	$19,095
One Piston	Route Emissions to a New Combustion Device	95%	$38,469	$19,095

Source: EPA, 2022.

Liquids Unloading

As described in EPA, 2021, the accumulation of liquids in new or mature wells[78] can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production (i.e., liquids loading), removal of fluids (i.e., liquids unloading) is required in order to maintain production. Gas wells therefore often need to remove or “unload” accumulated liquids to maintain gas production.

This analysis models two liquid unloading techniques (i.e.; with and without the use of a plunger lift). For liquids unloading that do not employ plunger lift, emissions occur when there is

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[78] In new gas wells, there is generally sufficient reservoir pressure/gas velocity to facilitate the flow of water and hydrocarbon liquids through the well head and to the separator to the surface along with produced gas. In mature gas wells, the accumulation of liquids in the wellbore can occur when the bottom well pressure/ gas velocity approaches average pressure.

venting of a well, typically to an atmospheric tank. For example, a common unloading method manually diverts the well's flow from a production separator to an atmospheric pressure tank. Under this scenario, venting to the atmospheric tank occurs because the separator operates at a higher pressure than the atmospheric tank and the well will temporarily flow to the atmospheric tank (which has a lower pressure than the pressurized separator). Natural gas is released through the tank vent to the atmosphere until liquids are unloaded.

For liquids unloading performed using a plunger lift, liquids may be removed manually or by automation. This method closes (shuts in) the well by lowering the plunger below the accumulated liquids in the well bore, which increases the reservoir pressure. Liquid is removed by the plunger when the well is reopened and the gas in the well pushes the plunger and the liquid back up the well bore (based on pressure differential). Emissions occur if the plunger does not return to the surface as expected, or when the plunger controller bypasses the separator and directs the flow to a lower pressure atmospheric pressure vent.

Table C-8 summarizes the mitigation technology and costs assumptions obtained from the NSPS OOOOb/EG OOOOc technical analysis (EPA,2021). For costs, the analysis assumes 25 percent of the average duration of a liquids unloading event would be the additional time required to implement BMP (i.e., monitoring and following steps to minimize/eliminate venting of emissions). It is assumed that persons implementing BMPs are already onsite, and no travel costs would be required. An average duration of a liquids unloading venting event (1.9 hours) was obtained from the API/ANGA Report.189 Thus, the time assumed to be needed to implement the BMP per unloading event was 0.475 hours per event. The reported cost per event assumes technical hour rate for plant and system operators, gas plant operators ($71.47/hr).

Table C-8 Technology and Cost Inputs by Mitigation Option in Production; Gathering and Boosting; Transmission and Storage

Segment	Mitigation Option	Reduction Efficiency	Capital Costs ($2019)	O&M Costs[a] ($2019)
Production	Liquids Unloading - Without Plunger Lift - 10% Control	10%	-	$65
Production	Liquids Unloading - Without Plunger Lift - 25% Control	25%	-	$65
Production	Liquids Unloading - Without Plunger Lift - 50% Control	50%	-	$65
Production	Liquids Unloading - With Plunger Lift - 10% Control	10%	-	$65
Production	Liquids Unloading - With Plunger Lift - 25% Control	25%	-	$65

Production	Liquids Unloading - With Plunger Lift - 50% Control	50%	-	$65

[a][1.9-hour event X 0.475 hour] X $71.74 hour = $64.75/event
Source: EPA, 2022.

Centrifugal Compressors

Table C-9 summarizes the technology costs and reduction efficiency assumptions obtained from the analysis update (EPA, 2022 and 2021). For wet seal centrifugal compressors, the technologies included: (1) routing emissions to a control device that achieves an emission reduction of 95.0 percent, (2) routing emissions to a process, and (3) implementing maintenance and repair activities to meet a numerical emission limit. For dry seal compressors, the mitigation technology was (1) direct inspection and maintenance/repair and routing to an enclosed combustor.

Table C-9 Technology and Cost Inputs by Mitigation Option in Production; Gathering and Boosting; Transmission and Storage

Segment	Site Type	Mitigation Option	Reduction Efficiency	Capital Costs ($2019)	O&M Costs ($2019)
Production	New	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Dry Seal Centrifugal Comp	37%	$0	$15,000
Production	Existing	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Dry Seal Centrifugal Comp	37%	$0	$15,000
Production	New	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Wet Seal Centrifugal Comp	89%	$0	$25,000
Production	Existing	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Wet Seal Centrifugal Comp	89%	$0	$25,000
Production	New	Emissions Routed to a New Combustion Device – Wet Seal Centrifugal Comp	95%	$80,926	$128,683
Production	Existing	Emissions Routed to a Existing Combustion	95%	$26,214	$3,732

		Device – Wet Seal Centrifugal Comp			
G&B	New	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Dry Seal Centrifugal Comp	37%	$0	$15,000
G&B	Existing	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Dry Seal Centrifugal Comp	37%	$0	$15,000
G&B	New	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Wet Seal Centrifugal Comp	89%	$0	$25,000
G&B	Existing	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Wet Seal Centrifugal Comp	89%	$0	$25,000
G&B	New	Emissions Routed to a New Combustion Device – Wet Seal Centrifugal Comp	95%	$80,926	$128,683
G&B	Existing	Emissions Routed to a Existing Combustion Device – Wet Seal Centrifugal Comp	95%	$26,214	$3,732
T&S	New	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Dry Seal Centrifugal Comp	37%	$0	$15,000
T&S	Existing	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Dry Seal Centrifugal Comp	37%	$0	$15,000
T&S	New	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Wet Seal Centrifugal Comp	54%	$0	$25,000
T&S	Existing	Direct Inspection and Maintenance/Repair Option and Routing to An Enclosed Combustor Option – Wet Seal Centrifugal Comp	54%	$0	$25,000

T&S	New	Emissions Routed to a New Combustion Device – Wet Seal Centrifugal Comp	95%	$80,926	$128,683
T&S	Existing	Emissions Routed to a Existing Combustion Device – Wet Seal Centrifugal Comp	95%	$26,214	$3,732

Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder.

For this analysis, the projected baseline emissions are estimates for two types of emission (1) emissions from rod packing system, and (2) fugitive leaks from reciprocating compressors. We applied the Rod Packing Change Out option to the first emissions stream. The annual monitoring option applied to the fugitive emissions.

Options to reduce emissions from reciprocating compressors include limiting leaks of natural gas past the piston rod packing unit. Two alternative approaches are analyzed in this analysis, these include: (1) specifying a frequency for the replacement of the compressor rod packing, (2) monitoring the emissions from the compressor and replacing the rod packing when the results exceed a specified threshold. Table C-10 summarizes the technologies used in the analysis by segment and compressor type.

Table C-10 Technology and Cost Inputs by Mitigation Option in Production; Gathering and Boosting; Transmission and Storage

Segment	Site Type	Mitigation Option	Reduction Efficiency	Capital Costs ($2019)	O&M Costs ($2019)
Production	New	Rod Packing Change Out	56%	$6,345	$1,963

Production	New	Annual Monitoring to Evaluate Need for Packing Replacement	92%	$6,345	$2,560
Production	Existing	Rod Packing Change Out	56%	$6,345	$1,963
Production	Existing	Annual Monitoring to Evaluate Need for Packing Replacement	92%	$6,345	$2,560
G&B	New	Rod Packing Change Out	56%	$6,345	$1,963
G&B	New	Annual Monitoring to Evaluate Need for Packing Replacement	92%	$6,345	$2,560
G&B	Existing	Rod Packing Change Out	56%	$6,345	$1,963
G&B	Existing	Annual Monitoring to Evaluate Need for Packing Replacement	92%	$6,345	$2,560
Processing	New	Rod Packing Change Out	80%	$4,807	$1,682
Processing	New	Annual Monitoring to Evaluate Need for Packing Replacement	92%	$4,807	$2,279
Processing	Existing	Rod Packing Change Out	80%	$4,807	$1,682
Processing	Existing	Annual Monitoring to Evaluate Need for Packing Replacement	92%	$4,807	$2,279
T&S	New	Rod Packing Change Out - **Transmission**	80%	$6,345	$1,963
T&S	New	Annual Monitoring to Evaluate Need for Packing Replacement - Transmission	92%	$6,345	$2,560
T&S	Existing	Rod Packing Change Out - Transmission	80%	$6,345	$1,963
T&S	Existing	Annual Monitoring to Evaluate Need for Packing Replacement - Transmission	92%	$6,345	$2,560
T&S	New	Rod Packing Change Out - Storage	77%	$8,653	$2,332
T&S	New	Annual Monitoring to Evaluate Need for Packing Replacement - Storage	92%	$8,653	$2,929
T&S	Existing	Rod Packing Change Out - Storage	77%	$8,653	$2,332
T&S	Existing	Annual Monitoring to Evaluate Need for Packing Replacement - Storage	92%	$8,653	$2,929

Source: EPA, 2022.

Emission Reductions and Mitigation Costs

The abatement potential achievable under the WEC analysis is summarized by segment and source in Table C-11. In 2024, our analysis estimates cost effective mitigation potential to be approximately 150 ktCH4. This potential increases in the following year to over 300 ktCH4 and then drops to 47 ktCH4 for years 2026 through 2035.

Table C-11 Abatement Potential by Industry Segment and Source Type

Segment/Source[a]	2024	2025	2026	2027
Onshore Production	75.45	143.00	247.41	-
Offshore Production	1.59	3.17	4.76	4.76
Gathering and Boosting	63.33	134.79	196.99	-
Natural Gas Processing	6.43	12.80	18.83	-
Natural Gas Transmission Compression	1.69	3.39	5.06	-
Natural Gas Transmission Pipeline	-	-	-	-
Underground Natural Gas Storage	-	-	-	-
LNG Import/Export	-	-	-	-
LNG Storage	-	-	-	-
Total Abatement Potential	**148.48**	**297.15**	**473.06**	**4.76**

Author's Calculations. [a] NG pipeline transmission and storage, LNG import/export and storage are not included in the analysis because emissions from these sources did not exceed the WEC threshold criteria. As a result, no abatement is reported for these segments.

It is important to note several key assumptions and data limitations associated with these estimates.

First, the analysis presented in the RIA and the resulting mitigation potentials reflect the baseline projections of emissions developed specifically for this rule making effort. See section 3 of the RIA for additional description of the baseline projections and what assumptions and caveats are included in the final projection values. As shown in Table C-11 there are no applicable emissions subject to WEC in the transmission pipeline, gas storage and LNG segments.

Additionally, the mitigation potential reported is the quantity of abatement available at mitigation costs ($/tCH4) less than the WEC price ($/tCH4) in a given year. There is significant addition abatement available at prices above the WEC, but we assume that facilities where the cost of implementing mitigation technologies is more expensive that the WEC fee, these facilities would choose to pay the fee as it would be the more economical option.

Finally, the abatement potential reported in Table C-11 reflects an exogenous assumption of adoption "phase in", where only one third of the full abatement potential estimated is assumed to be achievable in 2024. This assumption increases to two thirds in 2025 and then increases to full mitigation potential by 2026. These “phase in” constraints are intended to reflect the fact that facilities need time to assess the mitigation options and costs before implementing them. As a result, the amount of mitigation observed in the first two years would be some fraction of the full economical (e.g. Mit Cost ≤ WEC) mitigation potential.

The MAC curve is a composite and the corresponding mitigation options available to the applicable segments of the Oil and Natural Gas Industry subject to the WEC rule. Figure C-2 below shows the aggregate MAC curve for the industry, which shows cost-effective mitigation potential of ~445 tCH_4 in 2024. Figure C-3 through 5 below, show the disaggregated MAC curves by segment (i.e. production, G&B, T&S) illustrating the differences in mitigation potential across the industry segments. The largest share of cost-effective mitigation potential is available in the production segment (Figure C-3), accounting for approximately 252 2 tCH_4 in 2024 or ~52% of the total abatement potential. Gathering and boosting and processing (Figure C-4) offers the next largest potential of cost-effective reductions, approximately 209 tCH_4 accounting for another ~47% of 2024 abatement potential. Finally, Transmission and Storage (Figure C-5) provides the remaining 5 tCH_4 of cost-effective abatement.

Figure C-2 Total MAC Curve for WEC Applicable Segments of the Oil and Gas Industry in 2024

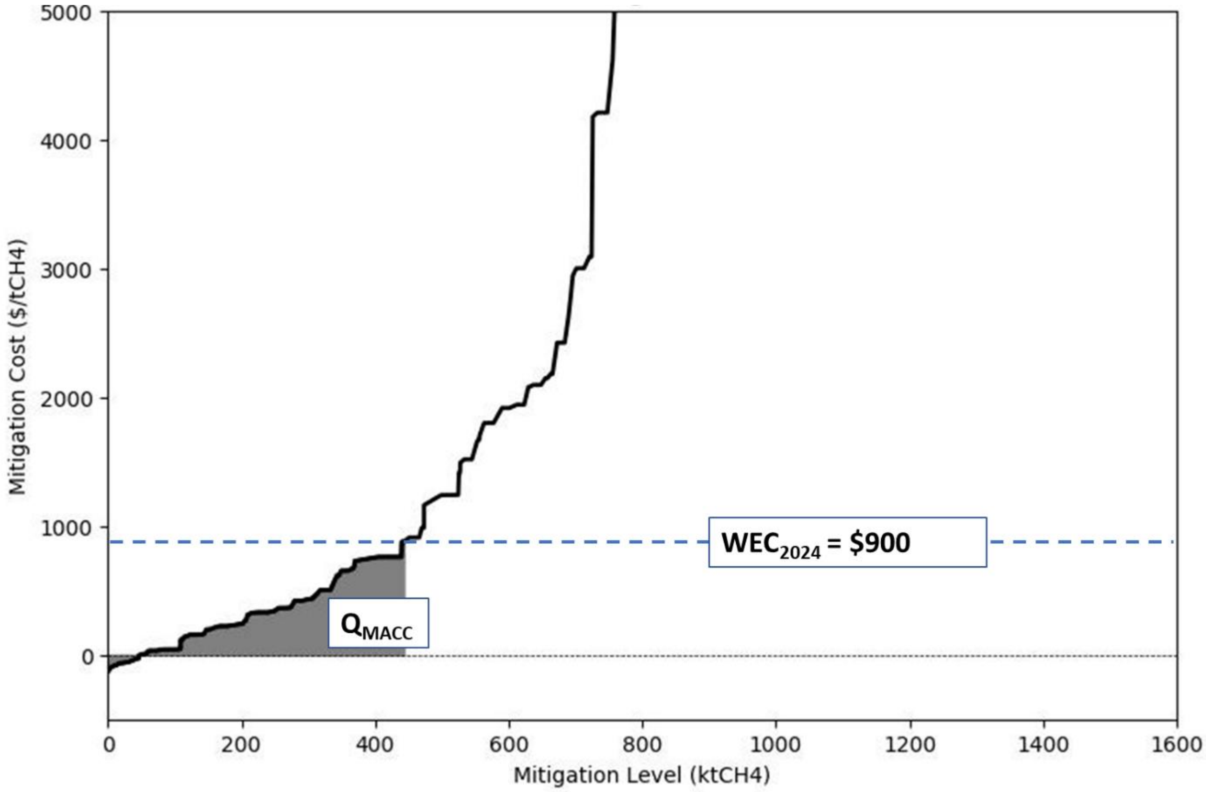

Figure C-3 Production Segment MAC Curve in 2024

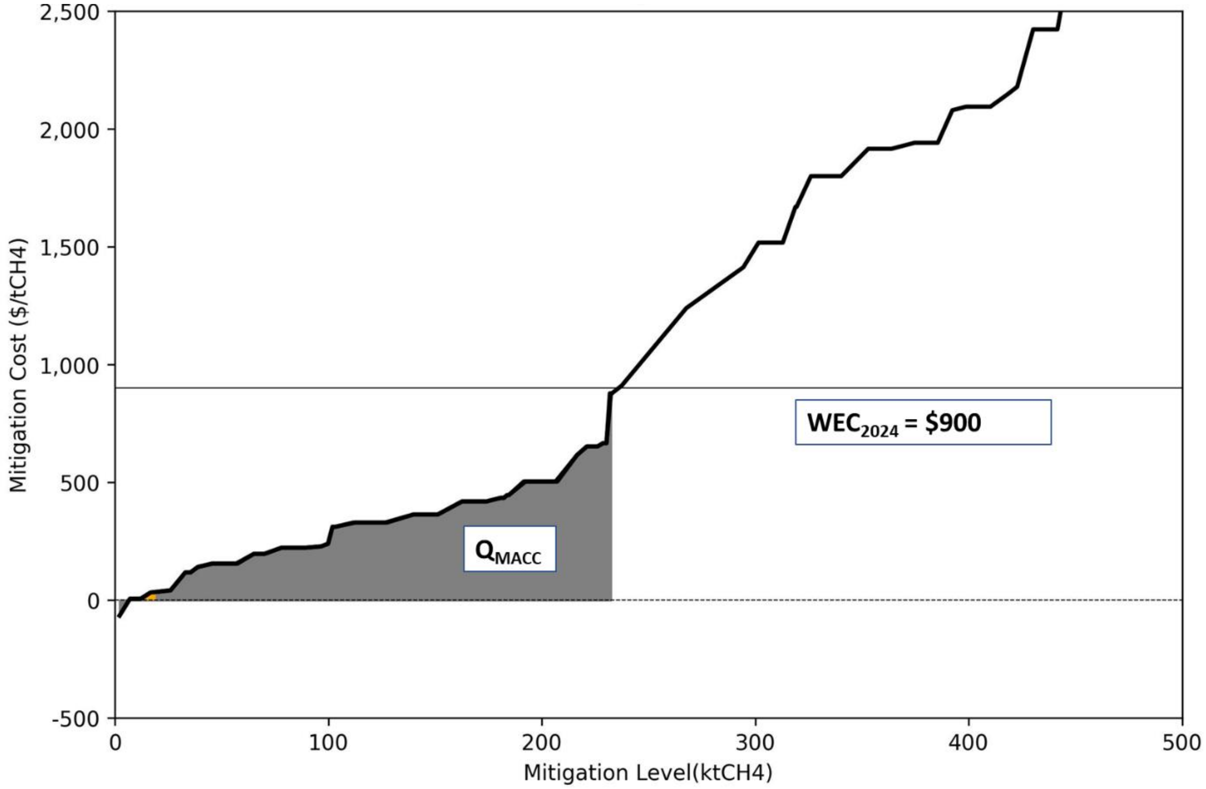

Figure C-4 G&B and Processing Segments MAC Curve in 2024

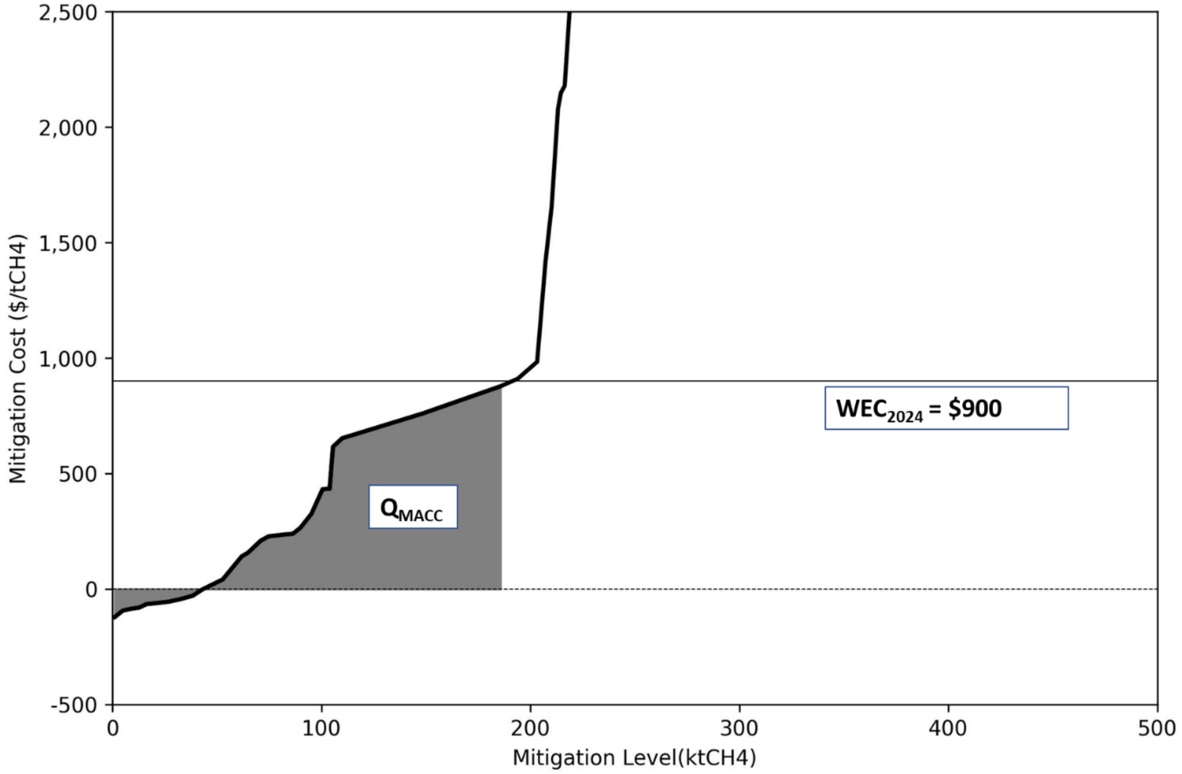

Figure C-5 Transmission and Storage Segment MAC Curve in 2024

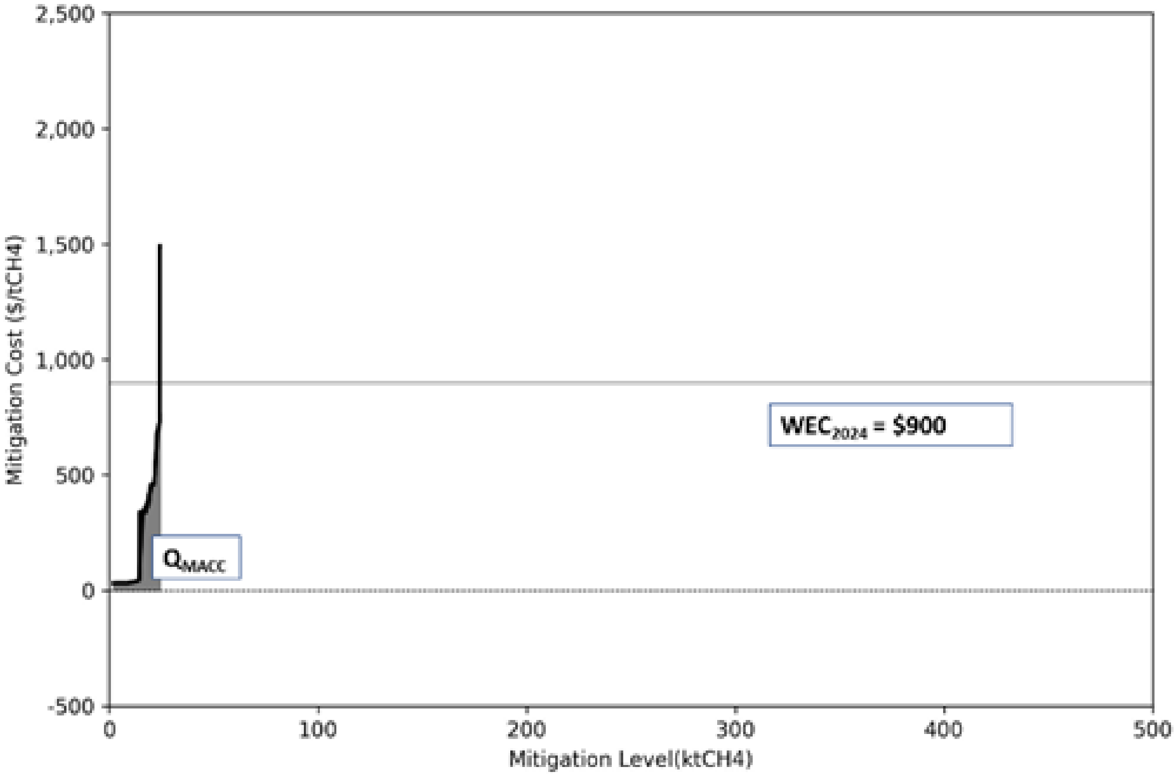

Table C-12 to Table C-14 provide snapshots of the mitigation results in years 2024, 2026 and 2030. In each table we report the full mitigation potential, the cost-effective abatement potential, potential after applying the “phase in” constraint. In addition, each table share the breakdown of cost to achieve the "phase in” abatement potential both with and without the inclusion of offsets of revenue from gas and non-gas savings.

Table C-12 Abatement Potential and Mitigation Costs by Segment and Source, 2024

Industry Segment / Source	Total MACC Technical Abatement Potential (kt)	Cost-Effective Abatement Below WEC (kt)	MACC Abatement Incl. Phase-In (kt)	Total Cost with Revenue (million $)	Total Cost without Revenue (million $)
Onshore Production	**623**	**226**	**75**	**$23.5**	**$33.7**
Pneumatic Controllers	475	181	60	$19.9	$28.9
Fugitive Emissions	66	0	0	$0.0	$0.0
Compressors	24	15	5	$0.4	$0.4
Pneumatic Pumps	43	17	6	$1.5	$2.0
Liquids Unloading	14	13	4	$1.7	$2.4
Offshore Production	**5**	**5**	**2**	**$0.1**	**$0.3**
Fugitive Emissions	5	5	2	$0.1	$0.3
Gathering and Boosting	**231**	**190**	**63**	**$25.4**	**$32.9**
Pneumatic Controllers	111	93	31	$6.4	$10.1
Fugitive Emissions	70	70	23	$17.6	$21.1
Compressors	32	20	7	$0.7	$0.8
Pneumatic Pumps	18	7	2	$0.6	$0.8
Natural Gas Processing	**19**	**19**	**6**	**$1.1**	**$1.6**
Fugitive Emissions	0	0	0	$0.0	$0.0
Compressors	19	19	6	$1.1	$1.6
Transmission and Storage	**5**	**5**	**2**	**$0.6**	**$0.7**
Pneumatic Controllers	0	0	0	$0.0	$0.0
Fugitive Emissions	0	0	0	$0.0	$0.0
Compressors	5	5	2	$0.6	$0.6
Total	**884**	**445**	**148**	**$50.6**	**$69.1**

Table C-13 Abatement Potential and Mitigation Costs by Segment and Source, 2026

Industry Segment / Source	Total MACC Technical Abatement Potential (kt)	Cost-Effective Abatement Below WEC (kt)	MACC Abatement Incl. Phase-In (kt)	Total Cost with Revenue (million $)	Total Cost without Revenue (million $)
Onshore Production	**519**	**247**	**247**	**$121.4**	**$156.6**
Pneumatic Controllers	381	145	145	$44.2	$67.8
Fugitive Emissions	61	47	47	$56.4	$64.0
Compressors	24	24	24	$9.5	$9.7
Pneumatic Pumps	39	18	18	$6.8	$8.4
Liquids Unloading	14	13	13	$4.5	$6.6
Offshore Production	**5**	**5**	**5**	**$0.1**	**$0.9**
Fugitive Emissions	5	5	5	$0.1	$0.9
Gathering and Boosting	**217**	**197**	**197**	**$87.6**	**$111.5**
Pneumatic Controllers	97	87	87	$21.3	$32.6
Fugitive Emissions	70	70	70	$50.7	$62.1
Compressors	32	32	32	$12.5	$13.0
Pneumatic Pumps	18	8	8	$3.1	$3.9
Natural Gas Processing	**19**	**19**	**19**	**$3.1**	**$4.6**
Fugitive Emissions	0	0	0	$0.0	$0.0
Compressors	19	19	19	$3.1	$4.6
Transmission and Storage	**5**	**5**	**5**	**$1.8**	**$2.0**
Pneumatic Controllers	0	0	0	$0.0	$0.1
Fugitive Emissions	0	0	0	$0.0	$0.0
Compressors	5	5	5	$1.8	$1.9
Total	**765**	**473**	**473**	**$214.0**	**$275.6**

Table C-14 Abatement Potential and Mitigation Costs by Segment and Source, 2030

Industry Segment / Source	Total MACC Technical Abatement Potential (kt)	Cost-Effective Abatement Below WEC (kt)	MACC Abatement Incl. Phase-In (kt)	Total Cost with Revenue (million $)	Total Cost without Revenue (million $)
Onshore Production	**0**	**0**	**0**	**$0.0**	**$0.0**
Pneumatic Controllers	0	0	0	$0.0	$0.0
Fugitive Emissions	0	0	0	$0.0	$0.0
Compressors	0	0	0	$0.0	$0.0
Pneumatic Pumps	0	0	0	$0.0	$0.0
Liquids Unloading	0	0	0	$0.0	$0.0
Offshore Production	**5**	**5**	**5**	**$0.1**	**$0.9**
Fugitive Emissions	5	5	5	$0.1	$0.9
Gathering and Boosting	**0**	**0**	**0**	**$0.0**	**$0.0**
Pneumatic Controllers	0	0	0	$0.0	$0.0
Fugitive Emissions	0	0	0	$0.0	$0.0
Compressors	0	0	0	$0.0	$0.0
Pneumatic Pumps	0	0	0	$0.0	$0.0
Natural Gas Processing	**0**	**0**	**0**	**$0.0**	**$0.0**
Fugitive Emissions	0	0	0	$0.0	$0.0
Compressors	0	0	0	$0.0	$0.0
Transmission and Storage	**0**	**0**	**0**	**$0.0**	**$0.0**
Pneumatic Controllers	0	0	0	$0.0	$0.0
Fugitive Emissions	0	0	0	$0.0	$0.0
Compressors	0	0	0	$0.0	$0.0
Total	**5**	**5**	**5**	**$0.1**	**$0.9**

References

EPA. 2019. *Global Non-CO2 Greenhouse Gas Emission Projections & Marginal Abatement Cost Analysis: Methodology Documentation*. EPA-430-R-19-012. Available at: https://www.epa.gov/sites/production/files/2019-09/documents/nonco2_methodology_report.pdf.

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EPA. 2021. *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review; Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG).*

Fact Sheet

Proposed Rule: Waste Emissions Charge for Petroleum and Natural Gas Systems

Action

- The U.S. Environmental Protection Agency (EPA) is proposing a regulation to implement provisions of the Inflation Reduction Act that require the Agency to collect an annual Waste Emissions Charge (WEC) on methane emissions from oil and natural gas facilities that exceed specific levels of emissions and methane intensity specified in the IRA.

- The WEC is designed to work together with EPA's Clean Air Act rules for oil and natural gas facilities, and with other provisions of the IRA, to incentivize and encourage reductions in harmful air pollution and waste from oil and natural gas operations. The proposal includes calculation procedures, exemptions, and reporting requirements related to the WEC.

Background

- In August 2022, the Inflation Reduction Act of 2022 (IRA) was signed into law. Section 60113 of the IRA amended the CAA by adding section 136, "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems." CAA section 136(c) directs the Administrator of EPA to impose and collect a WEC on methane emissions that exceed statutorily specified waste emissions levels from an owner or operator of an "applicable facility." The waste emissions level is a facility-specific amount of methane emissions (metric tons) calculated using segment-specific methane intensity levels defined in CAA section 136(f)(1)-(3) and the amount of natural gas (or oil, in certain circumstances) that the facility sends to sale.

- **The Waste Emissions Charge is just one element of the Methane Emission Reduction Program (MERP), which Congress included in the IRA to reduce harmful methane emissions from oil and gas operations**.

- In the IRA**, Congress expressly recognized EPA's authority to address methane pollution from oil and gas operations under the Clean Air Act – and built a three-part framework of additional measures** to complement that authority and drive reductions in methane from the oil and gas sector.

- As contemplated by Congress in the IRA, **EPA issued a final rule last December under section 111 of the Clean Air Act to achieve substantial and sustained reductions in methane emissions** from new and existing oil and gas operations.

- **EPA is also working to implement the three-part framework of the Inflation Reduction Act's Methane Emissions Reduction Program** (MERP) to help states, industry and

communities implement recently issued Clean Air Act standards and slash methane emissions:
  - **First,** utilizing resources provided by Congress in the IRA, EPA is partnering with the Department of Energy (DOE) to provide **over $1 billion dollars in financial and technical assistance** to **accelerate the transition** to no- and low- emitting oil and gas technologies, including funds for activities associated with low-producing conventional wells; support methane monitoring; and reduce pollution from oil and gas operations.
  - **Second, on August 1, 2023, as directed by Congress, EPA proposed revisions to Subpart W of the Greenhouse Gas Reporting Program** to ensure that reporting of methane emissions from oil and natural gas operations is based on empirical data and accurately reflects emissions.
  - **Third, EPA is proposing a regulation to implement the Waste Emissions Charge.** To take advantage of near-term opportunities for methane reductions while EPA and states work toward full implementation of the final Clean Air Act rule, Congress directed EPA to collect a charge on methane emissions from large oil and gas facilities that are **high-emitting** and **wasteful** based on data submitted under subpart W.

Overview

- The WEC is specifically tailored to impose a charge on high-emitting oil and gas facilities to incentivize actions to reduce wasteful methane emissions while EPA and states work toward full implementation of the CAA rule.

- The WEC is required by CAA section 136(e) to apply to emissions occurring in year 2024 at $900 per metric ton of methane, increasing to $1,200 per metric ton of methane in 2025, and to $1,500 per metric ton of methane in 2026 and in the years after. The WEC only applies to the subset of a facility's emissions that exceed the levels set by Congress, and that are not exempt from the charge.

- An applicable facility, as defined in CAA section 136(d), is a facility within the following industry segments (as defined in 40 CFR part 98, subpart W): onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, onshore petroleum and natural gas gathering and boosting, onshore gas transmission compression, onshore natural gas transmission pipeline, underground natural gas storage, liquefied natural gas import and export equipment, and liquefied natural gas storage. Only applicable facilities that report more than 25,000 metric tons of carbon dioxide equivalent under subpart W would be subject to the WEC.

Proposed Requirements

- EPA is proposing methodologies for calculating the amount by which a facility's reported methane emissions are below or in exceedance of the waste emissions threshold, and the total WEC owed by a facility owner or operator.

- EPA is also proposing approaches for implementing the three exemptions created by Congress, which may lower a facility's WEC or exempt the facility entirely from the charge.
    - *Unreasonable Delay*: This exemption would apply to methane emissions caused by unreasonable delay in environmental permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation.
    - *Plugged Wells*: This exemption would apply to the methane emissions from wells that have been permanently shut-in and plugged in the previous year in accordance with all applicable closure requirements.
    - *Regulatory Compliance*: This exemption would apply to facilities that are subject to and in compliance with methane emissions requirements promulgated pursuant to CAA sections 111(b) and (d), when and if certain statutorily specified conditions are met.

- EPA is proposing an approach for allowing the netting of emissions across different facilities owned by the same owner or operator, as required by Congress. Netting would mean that if an owner or operator has multiple applicable facilities reporting more than 25,000 metric tons of carbon dioxide equivalent to subpart W under common ownership or control, the emissions above and below the waste emissions thresholds from all applicable facilities can be summed to calculate net emissions. If net emissions are positive, this value would be multiplied by the annual $/metric-ton value to calculate the total WEC owed. If net emissions are less than or equal to zero, no WEC would be owed.

- EPA is proposing to require that the WEC would be quantified and paid through a WEC filing submitted no later than March 31 of each calendar year for methane emissions that occurred in the previous calendar year. The WEC filing would include information relevant to calculating the WEC, such as identification of facilities included in netting, eligibility for exemptions from WEC, and supporting information necessary for EPA to verify the WEC filing.

- As required by Congress, the WEC would first apply to emissions that occur in the 2024 reporting year (i.e., 2024 calendar year). EPA is proposing that owners or operators of applicable facilities would be required to submit a WEC filing for the 2024 reporting year by March 31, 2025. EPA is taking comment on whether the filing deadline should be extended for the first reporting year.

- The WEC would be calculated primarily using data reported under subpart W. In the subpart W rulemaking, EPA proposed that revisions to the emissions quantification methodologies would go into effect for the 2025 reporting year. EPA is currently reviewing comments received on the subpart W proposal, including those supporting the optional use of empirical data for the 2024 reporting year for the purpose of calculating the 2024 WEC. Any flexibilities that allow facility owners or operators to voluntarily submit empirical data for the 2024 reporting year will be addressed in the final subpart W rule.

- EPA is proposing that the WEC filing, remittance of applicable WEC, and any other submittals be submitted electronically.

- Waste Emissions Charge revenues will go to the general Treasury, as required by the Miscellaneous Receipts Act. The revenue does not go to EPA and EPA does not control how Waste Emissions Charge revenue is used.

More Information

- For an unofficial prepublication version of this action, please visit our Web site: https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program. The *Federal Register* notice for this proposal will be posted on this webpage when it is available.

- EPA will hold a virtual public hearing for this proposed action. Further details will be announced on our Web site: https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program.

- There is a 45-day public comment period following publication of the proposal in the *Federal Register*. Detailed instructions on how to provide comments are located in the preamble of the proposed rule.

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 2 and 99

[EPA-HQ-OAR-2023-0434; FRL-10246.1-01-OAR]

RIN 2060-AW02

Waste Emissions Charge for Petroleum and Natural Gas Systems

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing a regulation to implement the requirements of the Clean Air Act (CAA) as specified in the Methane Emissions Reduction Program of the Inflation Reduction Act. This program requires the EPA to impose and collect an annual charge on methane emissions that exceed specified waste emissions thresholds from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to the petroleum and natural gas systems source category requirements of the Greenhouse Gas Reporting Rule. The proposal would implement calculation procedures, flexibilities, and exemptions related to the waste emissions charge and proposes to establish confidentiality determinations for data elements included in waste emissions charge filings.

DATES: *Comments*. Comments must be received on or before **[INSERT DATE 45 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**.

Public hearing. The EPA will conduct a virtual public hearing on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. See **SUPPLEMENTARY INFORMATION** for information on registering for a public hearing.

ADDRESSES: *Comments*. You may submit comments, identified by Docket ID No. EPA-HQ-OAR-2023-0434, by any of the following methods:

Federal eRulemaking Portal. *https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.

Mail: U.S. Environmental Protection Agency, EPA Docket Center, Air and Radiation Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.

Hand Delivery or Courier (by scheduled appointment only): EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations are 8:30 a.m.-4:30 p.m., Monday-Friday (except Federal holidays).

Instructions: All submissions received must include the Docket ID No. for this proposed rulemaking. Comments received may be posted without change to *https://www.regulations.gov*, including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the "Public Participation" heading of the **SUPPLEMENTARY INFORMATION** section of this document.

The virtual hearing will be held using an online meeting platform, and the EPA has provided information on its website (*https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program-merp*) regarding how to register and access the hearing. Refer to the **SUPPLEMENTARY INFORMATION** section for additional information.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Mr. Shaun Ragnauth, Climate Change Division, Office of Atmospheric Programs (MC-6207A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW, Washington, DC 20460; telephone number: (202) 343-9142; e-mail address: *merp@epa.gov*.

World wide web (WWW). In addition to being available in the docket, an electronic copy of this proposal will also be available through the WWW. Following the Administrator's signature, a copy of this proposed rule will be posted on the EPA’s Inflation Reduction Act Methane Emissions Reduction Program website at *https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program*.

SUPPLEMENTARY INFORMATION:

Written comments. Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2023-0434, at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA’s docket at *https://www.regulations.gov* any information you consider to be confidential business information (CBI), proprietary business information (PBI), or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.)

must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the web, cloud, or other file sharing system). Commenters who would like the EPA to further consider in this rulemaking comments relevant to this rulemaking that they previously provided on any other rulemaking or request for information (*e.g.*, the Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems, Docket ID No. EPA-HQ-OAR-2023-0234, the Methane Emissions Reduction Program Request for Information, Docket ID No. EPA-HQ-OAR-2022-0875, and the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Docket ID No. EPA-HQ-OAR-2021-0317) must submit those comments to the EPA during this proposal’s comment period. Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI, PBI, or multimedia submissions, and general guidance on making effective comments.

Participation in virtual public hearing. The EPA will begin pre-registering speakers for the hearing no later than one business day after publication in the *Federal Register*. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program* or contact us by email at *merp@epa.gov*. The last day to pre-register to speak at the hearing will be **[INSERT DATE 12 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. On

[INSERT DATE 14 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*], the EPA will post a general agenda that will list pre-registered speakers in approximate order at *https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program*.

The EPA will make reasonable efforts to follow the schedule as closely as practicable on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to *merp@epa.gov*. The EPA also recommends submitting the text of your oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program*. While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact us by email at *merp@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the *Federal Register* announcing updates.

If you require the services of an interpreter or special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by **[INSERT DATE 7 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. The EPA may not be able to arrange accommodations without advanced notice.

Regulated entities. This is a proposed regulation. If finalized, the regulation would affect certain owners or operators of facilities in certain segments of the petroleum and natural gas systems industry that report more than 25,000 metric tons (mt) of carbon dioxide equivalent (CO_2e) pursuant to the requirements codified at 40 CFR part 98, subpart W (Petroleum and Natural Gas Systems) (hereafter referred to as “part 98, subpart W”). Per the requirements of CAA section 136(d), the industry segments to which the waste emissions charge may apply are offshore petroleum and natural gas production, onshore petroleum and natural gas production, onshore natural gas processing, onshore gas transmission compression, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export equipment, onshore petroleum and natural gas gathering and boosting, and onshore natural gas transmission pipeline. Regulated categories and entities include, but are not limited to, those listed in Table 1 of this preamble:

Table 1. Examples of Affected Entities by Category

Category	North American Industry Classification System (NAICS)	Examples of affected facilities
	486210	Pipeline transportation of natural gas.

Category	**North American Industry Classification System (NAICS)**	**Examples of affected facilities**
Petroleum and Natural Gas Systems	221210	Natural gas distribution facilities.
	211120	Crude petroleum extraction.
	211130	Natural gas extraction.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this proposed action. This table lists the types of facilities that the EPA is now aware could potentially be affected by this action. Other types of facilities than those listed in the table could also be subject to reporting requirements. To determine whether you would be affected by this proposed action, you should carefully examine the applicability criteria found in 40 CFR part 99, subpart A (General Provisions). If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Acronyms and abbreviations. The following acronyms and abbreviations are used in this document.

AMLD	Advanced Mobile Leak Detection
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BOEM	Bureau of Ocean Energy Management
CAA	Clean Air Act
CBI	confidential business information
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations

CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
e-GGRT	electronic Greenhouse Gas Reporting Tool
EF	emission factor
EG	emission guidelines
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ET	Eastern time
FAQ	frequently asked question
FR	*Federal Register*
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GOR	gas-to-oil ratio
GRI	Gas Research Institute
GWP	Global Warming Potential
IRA	Inflation Reduction Act of 2022
ICR	Information Collection Request
ISBN	International Standard Book Number
ISO	International Standards Organization
LDC	local distribution company
LNG	liquified natural gas
mmBtu	million British thermal units
MMscf	million standard cubic feet
mt	metric tons
N_2O	nitrous oxide
NAICS	North American Industry Classification System
NGLs	natural gas liquids
NIST	National Institute of Standards and Technology
NSPS	new source performance standards

OEM	original equipment manufacturer
OGI	optical gas imaging
OMB	Office of Management and Budget
PBI	proprietary business information
ppm	parts per million
PRA	Paperwork Reduction Act
RFA	Regulatory Flexibility Act
RY	reporting year
scfh	standard cubic feet per hour
TSD	technical support document
U.S.	United States
UMRA	Unfunded Mandates Reform Act of 1995
UNFCCC	United Nations Framework Convention on Climate Change
VOC	volatile organic compound
WEC	waste emissions charge
WWW	World Wide Web

Table of Contents

I. Background

A. How is this Preamble Organized?

The first section (section I.) of this preamble contains background information regarding the proposed rule. This section also discusses the EPA’s legal authority under the Clean Air Act (CAA) to promulgate implementing regulations for the waste emissions charge, proposed to be codified at 40 CFR part 99 (hereafter referred to as "part 99"). Section I. of the preamble also discusses the EPA's legal authority to make confidentiality determinations for new data elements included in waste emissions charge filings (WEC filings) required by the proposed rule. Section II. of this preamble contains detailed information on the proposed provisions necessary to implement CAA section 136(c) through (g), including exemptions. Section III. of this preamble describes the general requirements for the proposed rule. Section IV. of this preamble discusses the proposed confidentiality determinations for new data reporting elements for the proposed part 99 and also discusses confidentiality determinations for two data elements reported under part 98, subpart W. Section V. of this preamble discusses the impacts of the proposed part 99. Section VI. of this preamble describes the statutory and Executive order requirements applicable to this proposed action.

B. Executive Summary

In August 2022, Congress passed, and President Biden signed, the Inflation Reduction Act of 2022 (IRA) into law. Section 60113 of the IRA amended the CAA by adding section 136, "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems." CAA section 136(c) directs the Administrator of the EPA to impose and collect a "Waste Emissions Charge" on methane emissions that exceed statutorily specified waste emissions thresholds from owners or operators of applicable facilities. The waste emissions threshold is a facility-specific amount of metric tons of methane emissions calculated using the segment-specific methane intensity thresholds defined in CAA section 136(f)(1) through (3) and a facility's natural gas throughput (or oil throughput in certain circumstances). Facilities that have methane emissions below the threshold would not be required to pay the charge; facilities that have emissions above the threshold would be required to pay the charge. The waste emissions charge, or WEC, is specified in CAA section 136 to begin for emissions occurring in 2024 at $900 per metric ton of methane exceeding the threshold, increasing to $1,200 per metric ton of methane in 2025, and to $1,500 per metric ton of methane in 2026 and years after. The WEC only applies to the subset of a facility’s emissions that are above the waste emissions threshold.

The WEC program applies to facilities that report more than 25,000 mt CO_2e of greenhouse gases emitted per year pursuant to the Greenhouse Gas Reporting Rule’s requirements for the petroleum and natural gas systems source category (codified as 40 CFR part 98, subpart W).[1] An applicable facility, as defined in CAA section 136(d), is a facility within the following industry segments (as the following industry segments are defined in part 98, subpart W): onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, onshore gas transmission compression, onshore natural gas transmission pipeline, underground natural gas storage, liquefied natural gas import and export equipment, and liquefied natural gas storage.[2] Congress structured the WEC so that it focuses on high-emitting

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[1] 42 U.S.C. 7436(c) (“The Administrator shall impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W of part 98 of title 40, Code of Federal Regulations, regardless of the reporting threshold under that subpart.”).

[2] 42 U.S.C. 7436(d).

oil and gas facilities (*i.e.*, those with emissions greater than 25,000 mt CO_2e of greenhouse gases emitted per year and that have a methane emissions intensity in excess of the statutory threshold).

CAA section 136 defines three important elements of the WEC program: 1) waste emissions thresholds; 2) netting of emissions across different facilities; and 3) exemptions for certain emissions and facilities. Facilities may owe a WEC obligation if their subpart W reported emissions exceed facility-specific waste emissions thresholds specified in CAA section 136(f).[3] Facility efficiency in terms of methane emissions per unit of production or throughput would have a large impact on the amount of the WEC owed, with more efficient facilities expected to have emissions falling below the specified thresholds.

Some facilities may have emissions that are below the waste emissions thresholds, and some facilities may have emissions above the thresholds. CAA section 136(f)(4) allows facilities under common ownership or control to net emissions across those facilities, which could result in a reduced total charge, or avoidance of the charge.[4]

In addition, there are three exemptions that may lower a facility's WEC or exempt the facility entirely from the charge. The first exemption, found in CAA section 136(f)(5), exempts from the charge emissions occurring at facilities in the onshore or offshore petroleum and natural

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[3] 42 U.S.C. 7436(f)(1-3).

[4] 42 U.S.C. 7436(f)(4) ("In calculating the total emissions charge obligation for facilities under common ownership or control, the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments identified in subsection (d).").

gas production industry segments that are caused by eligible delays in environmental permitting of gathering or transmission infrastructure.[5] The second exemption, found in CAA section 136(f)(6), exempts from the charge, if certain conditions are met, those facilities that are subject to and in compliance with final methane emissions requirements promulgated pursuant to CAA sections 111(b) and (d).[6] This exemption becomes available only if a determination is made by the Administrator that such final requirements are approved and in effect in all states with respect to the applicable facilities, and that the emissions reductions resulting from those final requirements will achieve equivalent or greater emission reductions as would have resulted from the EPA's proposed methane emissions requirements from 2021.[7] The third exemption, found in CAA section 136(f)(7), exempts from the charge reporting-year emissions from wells that are

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[5] 42 U.S.C. 7436(f)(5). ("Charges shall not be imposed pursuant to paragraph (1) on emissions that exceed the waste emissions threshold specified in such paragraph if such emissions are caused by unreasonable delay, as determined by the Administrator, in environmental permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation.")

[6] 42 U.S.C. 7436(f)(6) ("Charges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 7411 of this title upon a determination by the Administrator that—(i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 7411 of this title have been approved and are in effect in all States with respect to the applicable facilities; and (ii)compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 FR 63110 (November 15, 2021)), if such rule had been finalized and implemented.").

[7] *Id.*

permanently shut in and plugged.[8] In this action, the EPA proposes specific requirements for eligibility for each of these exemptions.

The EPA proposes to require that the WEC would be quantified and paid through a WEC filing submitted no later than March 31 of each calendar year for methane emissions that occurred in the previous calendar year (subpart W reporting year). The WEC filing would include information relevant to calculating the WEC, such as identification of facilities included in netting, eligibility for exemptions from WEC, and supporting information necessary for the EPA to verify information submitted regarding exemptions.

The proposed provisions of part 99 under this rulemaking are described in further detail in sections II. and III. of this preamble.

C. Background and Related Actions

Congress designed the WEC to work in tandem with several related EPA programs. The WEC provides an incentive for the early adoption of methane emission reduction practices and technologies such as those that required under the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (NSPS OOOOb/EG OOOOc), which Congress expected to be promulgated pursuant to CAA section 111. The sooner facilities adopt the methodologies and technologies required in those rules, the lower their assessed WEC; at full implementation of

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[8] 42 U.S.C. 7436(f)(7).(“ Charges shall not be imposed with respect to the emissions rate from any well that has been permanently shut-in and plugged in the previous year in accordance with all applicable closure requirements, as determined by the Administrator.”)

those rules, the EPA expects many of the WEC-affected facilities will be below the WEC emissions thresholds. To further support the overall goal of reducing methane emissions, CAA section 136(a) and (b) also provides $1.55 billion to, among other things, help finance the early adoption of emissions reduction methodologies and technologies and to support monitoring of methane emissions. More detailed background information on the impacts of methane on public health and welfare and the related regulatory activities is provided in section I.C.1. of this preamble.

1. How does methane affect public health and welfare?

Elevated concentrations of greenhouse gases (GHGs) including methane have been warming the planet, leading to changes in the Earth’s climate that are occurring at a pace and in a way that threatens human health, society, and the natural environment. While the EPA is not statutorily required to make any particular scientific or factual findings regarding the impact of GHG emissions on public health and welfare in support of the proposed WEC, the EPA is providing in this section a brief scientific background on methane and climate change to offer additional context for this rulemaking and to help the public understand the environmental impacts of GHGs such as methane.

As a GHG, methane in the atmosphere absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change, including increases in air and ocean temperatures, changes in precipitation patterns, retreating snow and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts. Methane also contributes to climate change through chemical reactions in the atmosphere that produce tropospheric ozone and stratospheric water vapor. In 2022, atmospheric concentrations of methane increased by nearly 17 parts per billion (ppb) over 2021 levels to reach 1912 ppb.[9] This was the largest increase since the start of the NOAA atmospheric record in 1984, with current concentrations now more than two and a half times larger than the preindustrial level.[10] Methane is responsible for about one third of all warming resulting from human emissions of well-mixed GHGs,[11] and due to its high radiative efficiency compared to carbon dioxide, methane mitigation is one of the best opportunities for reducing near-term warming.

Major scientific assessments continue to be released that further advance our understanding of the climate system and the impacts that methane and other GHGs have on public health and welfare both for current and future generations. According to the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report, “it is unequivocal that human influence has warmed the atmosphere, ocean and land. Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred.”[12] Recent EPA

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[9] NOAA, *https://gml.noaa.gov/webdata/ccgg/trends/ch4/ch4_annmean_gl.txt*.

[10] Blunden, J. and T. Boyer, Eds., 2022: “State of the Climate in 2021.” *Bull. Amer. Meteor. Soc.*, 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1*, 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1*

[11] IPCC, 2021: *Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 3−32, doi:10.1017/9781009157896.001

[12] *Id.*

modeling efforts[13] have also shown that impacts from these changes are projected to vary regionally within the U.S. For example, large damages are projected from sea level rise in the Southeast, wildfire smoke in the Western U.S., and impacts to agricultural crops and rail and road infrastructure in the Northern Plains. Scientific assessments, EPA analyses, and updated observations and projections document the rapid rate of current and future climate change and the potential range impacts both globally and in the United States,[14] presenting clear support regarding the current and future dangers of climate change and the importance of GHG emissions mitigation.

2. Related Actions

As mandated by CAA section 136(c) and (d), the applicability of the WEC is based upon the quantity of metric tons of CO_2e emitted per year pursuant to the requirements of subpart W. Further, CAA section 136(e) requires that the WEC amount be calculated based upon methane

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[13] (1) EPA. 2021. *Technical Documentation on the Framework for Evaluating Damages and Impacts (FrEDI)*. U.S. Environmental Protection Agency, EPA 430-R-21-004.
(2) Hartin C., E.E. McDuffie, K. Novia, M. Sarofim, B. Parthum, J. Martinich, S. Barr, J. Neumann, J. Willwerth, & A. Fawcett. Advancing the estimation of future climate impacts within the United States. EGUsphere doi: 10.5194/egusphere-2023-114, 2023.

[14] (1) USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018. Available at *https://nca2018.globalchange.gov*.
(2) IPCC, 2021: *Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Pe´an, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekc¸i, R. Yu and B. Zhou (eds.)]. Cambridge University Press.

emissions reported pursuant to subpart W. As a result, this proposed action builds upon previous subpart W rulemakings.

On August 1, 2023, the EPA proposed revisions to subpart W consistent with the authority and directives set forth in CAA section 136(h) as well as the EPA’s authority under CAA section 114 (88 FR 50282) (hereafter referred to as the “2023 Subpart W Proposal”). In that rulemaking, the EPA proposed revisions to require reporting of additional emissions or emissions sources to address potential gaps in the total methane emissions reported by facilities to subpart W. For example, these proposed revisions would add a new emissions source, referred to as “other large release events,” to capture large emission events that are not accurately accounted for using existing methods in subpart W. The EPA also proposed revisions to add or revise existing calculation methodologies to improve the accuracy of reported emissions, incorporate additional empirical data, and allow owners and operators of applicable facilities to submit empirical emissions data that could appropriately demonstrate the extent to which a charge is owed in implementation of CAA section 136, as directed by CAA section 136(h). The EPA also proposed revisions to existing reporting requirements to collect data that would improve verification of reported data, ensure accurate reporting of emissions, and improve the transparency of reported data. For clarity of discussion within this preamble, unless otherwise stated, references to provisions of subpart W (*i.e.*, 40 CFR 98.230 through 98.238) reflect the language as proposed in the 2023 Subpart W Proposal. The EPA’s intention in this proposed rulemaking is that the final WEC rule would update the proposed cross-references to subpart W to be consistent with the final Subpart W rule resulting from the 2023 Subpart W Proposal.

Under the Greenhouse Gas Reporting Program, the EPA also recently issued a supplemental proposal to a 2022 proposed rule (88 FR 32852, May 22, 2023), which included proposed updates to the General Provisions of the Greenhouse Gas Reporting Rule to reflect revised global warming potentials (GWPs), proposed reporting of GHG data from additional sectors (*i.e.*, non-subpart W sectors), and proposed revisions to source categories other than subpart W that would improve implementation of the Greenhouse Gas Reporting Rule. The proposed revision to the GWP of methane (from 25 to 28) is expected to lead to a small increase in the number of facilities that exceed the subpart W 25,000 mt CO_2e threshold and thus become subject to the proposed part 99 requirements. This supplemental proposed rule is not expected to otherwise impact subpart W reporting requirements as they pertain to the applicability or implementation of the proposed part 99 requirements.

In addition, on November 15, 2021 (86 FR 63110), the EPA proposed under CAA section 111(b) standards of performance regulating emissions of methane and volatile organic compounds (VOCs) for certain new, reconstructed, and modified sources in the oil and natural gas source category (proposed as 40 CFR part 60, subpart OOOOb) (hereafter referred to as “NSPS OOOOb”), as well as emissions guidelines regulating emissions of methane under CAA section 111(d) for certain existing oil and natural gas sources (proposed as 40 CFR part 60, subpart OOOOc) (hereafter referred to as “EG OOOOc”). The November 15, 2021 proposal (covering both NSPS OOOOb and EG OOOOc) – and which Congress explicitly referred to in section 136 – will be referred to hereafter as the “NSPS OOOOb/EG OOOOc 2021 Proposal.” The NSPS OOOOb/EG OOOOc 2021 Proposal sought to strengthen standards of performance previously in effect under section 111(b) of the CAA for new, modified and reconstructed oil and natural gas sources, and to establish emissions guidelines under section 111(d) of the CAA for states to follow in developing plans to limit methane emissions from existing oil and natural gas sources.

On December 6, 2022, the EPA issued a supplemental proposal to update, strengthen and expand upon the NSPS OOOOb/EG OOOOc 2021 Proposal (87 FR 74702). The December 6, 2022 supplemental proposal will be referred to hereafter as “NSPS OOOOb/EG OOOOc 2022 Supplemental Proposal.” This supplemental proposal modified certain standards proposed in the NSPS OOOOb/EG OOOOc 2021 Proposal and added proposed requirements for sources not previously covered. Among other things, the supplemental proposal sought to: ensure that all well sites are routinely monitored for leaks, with requirements based on the type and amount of equipment on site; encourage the deployment of innovative and advanced monitoring technologies by establishing performance requirements that can be met by a broader array of technologies; prevent leaks from abandoned and unplugged wells by requiring documentation that well sites are properly shut-in and plugged before monitoring is allowed to end; leverage qualified expert monitoring to identify “super-emitters” for prompt mitigation; and strengthen requirements for flares.

On December 2, 2023, in an action titled, *“*Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” the EPA finalized these two rules to reduce air emissions from the Crude Oil and Natural Gas source category under section 111 of the Clean Air Act.

First, the EPA finalized NSPS OOOOb regulating GHG (in the form of a limitation on emissions of methane) and VOCs emissions for the Crude Oil and Natural Gas source category pursuant to CAA section 111(b)(1)(B) (hereafter, "NSPS OOOOb"). Second, the EPA finalized presumptive standards in EG OOOOc to limit GHG emissions (in the form of methane limitations) from designated facilities in the Crude Oil and Natural Gas source category, as well as requirements under the CAA section 111(d) for states to follow in developing, submitting, and implementing state plans to establish performance standards (hereafter, "EG OOOOc").[15]

The NSPS OOOOb/EG OOOOc 2021 Proposal and Final NSPS OOOOb/EG OOOOc are relevant to this WEC proposal in two ways: first, WEC applicable facilities containing CAA section 111(b) and (d) facilities that are in compliance with the applicable standards are likely to have emissions below the thresholds specified in section II.B. of this preamble due to mitigation resulting from meeting the methane emissions requirements of NSPS OOOOb or EG OOOOc-implementing state and Federal plans, and therefore would not be expected to incur charges under the WEC program; and second, compliance with applicable standards (if certain criteria are met) may exempt facilities from the WEC under the regulatory compliance exemption outlined at CAA section 136(f)(6) (discussed in section II.D.2. of this preamble). As a part of the NSPS OOOOb/EG OOOOc 2022 Supplemental Proposal, the EPA requested comment on the criteria and approaches that the Administrator should consider in making the CAA section

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[15] In this action, the EPA also finalized several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021, under the CRA, disapproving the 2020 Policy Rule, and also finalized a protocol under the general provisions for use of Optical Gas Imaging.

136(f)(6)(A)(ii) equivalency determination, which is discussed at section II.D.2. of this preamble.

The EPA also opened a non-regulatory docket on November 4, 2022 and issued a Request for Information (RFI) seeking public input to inform program design related to CAA section 136.[16] As part of this request, the EPA sought input on issues that should be considered related to implementation of the WEC. The comment period closed on January 18, 2023.

The 2023 Subpart W Proposal, the NSPS OOOOb/EG OOOOc 2021 Proposal, the NSPS OOOOb/EG OOOOc 2022 Supplemental Proposal, and the November 2022 request for information are relevant to this proposal. While the EPA has reviewed or will review relevant comments submitted as part of the rulemaking actions and request for information, the EPA is not obligated to respond to those comments in this action since the comment solicitations did not accompany a proposal regarding the WEC. Commenters who would like the EPA to formally consider in this rulemaking any relevant comments previously submitted must resubmit those comments to the EPA during this proposal’s comment period.

In addition to the WEC requirement, and the related revisions to subpart W to facilitate accuracy of reporting and charge calculation, as noted in section I.C. of this preamble, CAA sections 136(a) and (b) provide $1.55 billion for the Methane Emissions Reduction Program, including for incentives for methane mitigation and monitoring. The EPA is partnering with the U.S. Department of Energy and National Energy Technology Laboratory to provide financial

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[16] Docket ID No. EPA-HQ-OAR-2022-0875.

assistance for monitoring and reducing methane emissions from the oil and gas sector, as well as technical assistance to help implement solutions for monitoring and reducing methane emissions. As designed by Congress, these incentives were intended to complement the regulatory programs and to help facilitate the transition to a more efficient petroleum and natural gas industry.

D. Legal Authority

The EPA is proposing this rule under its newly established authority provided in CAA section 136. As noted in section I.B. of this preamble, the IRA added CAA section 136, “Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems,” which requires that the EPA impose and collect an annual specified charge on methane emissions that exceed an applicable waste emissions threshold from an owner or operator of an applicable facility that reports more than 25,000 mt CO_2e of greenhouse gases emitted per year pursuant to subpart W of the GHGRP. Under CAA section 136, an “applicable facility” is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution).

The EPA is also proposing elements of this rule under its existing CAA authority provided in CAA section 114, as well as CAA section 301. CAA section 114(a)(1) authorizes the Administrator to require emissions sources, persons subject to the CAA, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide other information the Administrator requests for the purposes of carrying out any provision of the CAA (except for a provision of title II with respect to manufacturers of new motor vehicles or new motor vehicle engines). Thus, CAA section 114(a)(1) additionally provides the EPA broad authority to require the information that would be required by this proposed rule because the information is relevant for carrying out CAA section 136. Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations "as are necessary to carry out [its] functions under [the CAA]."

The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA. Section 307(d) contains a set of procedures relating to the issuance and review of certain CAA rules.

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing proposed confidentiality determinations for the new data elements required by this proposed regulation.

II. Requirements to Implement the Waste Emissions Charge

This section summarizes the EPA's proposed approach to calculating WEC, including how WEC would be calculated at the facility level, how netting of emissions from facilities under common ownership or control would be applied, the EPA's interpretation of common ownership or control, and how the exemptions established in CAA section 136(f) would be implemented.

A. Proposed Definitions to Support WEC Implementation

In accordance with CAA section 136(d), applicable facilities under part 99 are those facilities within certain industry segments as defined under part 98, subpart W. Thus, we are proposing several definitions within the general provisions of 40 CFR 99.2. First, as the statute specifies, we are proposing a definition of "applicable facility" to mean a facility within one or more of the following industry segments: onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, onshore natural gas transmission compression, onshore natural gas transmission pipeline, underground natural gas storage, LNG import and export equipment, or LNG storage, as those industry segments are defined in 40 CFR 98.230 of subpart W.[17] A single reporting facility under part 98, subpart W, typically consists of operations within a single industry segment. However, for certain industry segments a single reporting facility may represent operations in two or more industry segments. Industry segments that potentially may exist within the same reporting facility are onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG import and export equipment, and LNG storage. To accommodate for such facilities, we are proposing within the definition of "applicable facility" that such operations would be considered a single applicable facility under part 99.

We are also proposing a definition of "WEC applicable facility" in 40 CFR 99.2, which would mean an applicable facility for which the owner or operator of the subpart W reporting facility reported GHG emissions under subpart W of more than 25,000 mt CO_2e – the amount set in the statute. In cases where a subpart W facility reports under two or more of the industry segments listed in the previous paragraph, the EPA proposes that the 25,000 mt CO_2e threshold would be evaluated based on the total facility GHG emissions reported to subpart W across all of

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[17] *See* 42 U.S.C. 7436(d).

the industry segments (*i.e.*, the facility's total subpart W GHGs). As discussed in section II.B.1. of this preamble, the waste emissions threshold is the facility-specific threshold, based upon an industry segment-specific methane intensity threshold, above which the EPA must impose and collect the WEC. For the purposes of determining the waste emissions threshold for a WEC applicable facility that operates within multiple industry segments, the EPA proposes that each industry segment would be assessed separately (*i.e.*, using industry segment-specific throughput and methane intensity threshold) and then summed together to determine the waste emissions threshold for the facility. The EPA proposes that this approach would be used in all cases where a WEC applicable facility contains equipment in multiple subpart W industry segments.

The EPA requests comment on an alternative definition of WEC applicable facility as it applies to subpart W facilities that report under two or more industry segments. This alternative approach would assess these facilities against the 25,000 mt CO_2e applicability threshold using the CO_2e reported under subpart W for each individual segment at the facility rather than the total facility subpart W CO_2e reported across all segments. CAA section 136(d) defines an applicable facility as one "within" the nine industry segments subject to the WEC and does not specify that an applicable facility is in one and only one industry segment. The EPA understands this to mean that an applicable facility constitutes an entire subpart W facility, including those that report under more than one segment. Thus, based on the statutory text, the EPA proposes to assess WEC applicability based on the entire subpart W facility's emissions. Based on historic subpart W data, no more than two dozen facilities report data for multiple segments, and when total subpart W CO_2e is summed across all segments at these facilities, almost all of these facilities remain below the 25,000 mt CO_2e threshold. Historic data also show that the industry segments (onshore natural gas processing, onshore natural gas transmission compression, and underground natural gas storage) located at these facilities generally have methane emissions below the waste emissions thresholds. The proposed approach of using total subpart W facility CO_2e for determining WEC applicability therefore would not result in a significant number of facilities being regulated under WEC compared to an approach that assessed applicability using subpart W CO_2e for each individual industry segment at a facility. Based on historic data, the EPA does not expect the very small number of facilities with operations in multiple subpart W segments that could be subject to the WEC under the proposed approach to experience a substantially different financial impact under the alternative approach.

We are also proposing a definition for “WEC applicable emissions” in 40 CFR 99.2, which would mean the annual methane emissions, as calculated using equations specified in part 99, from a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the facility after consideration of any applicable exemptions. The proposed calculation methodology for WEC applicable emissions is addressed in section II.B.2. of this preamble. We are also proposing a definition for “facility applicable emissions” in 40 CFR 99.2 which would mean the annual methane emissions, as calculated using equations specified in part 99, from a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the facility prior to consideration of any applicable exemptions.

The proposed provisions of this part would apply to WEC obligated parties and WEC applicable facilities. In addition to the proposed definition for WEC applicable facility discussed earlier in this section, we are proposing a definition for the term WEC obligated party in 40 CFR 99.2. The term WEC obligated party refers to the owners or operators of one or more WEC applicable facilities. For WEC applicable facilities that have more than one owner or operator, we are proposing that the WEC obligated party is an owner or operator selected by a binding agreement among the owners and operators of the WEC applicable facility. The EPA anticipates that such an agreement would be similar to those used in carrying out 40 CFR 98.4(b) under the GHGRP.

For the purposes of submitting the WEC filing, we are proposing that the WEC obligated party's WEC applicable facilities are the WEC applicable facilities for which it is the owner or operator (including through binding agreement as noted above), as of December 31 of each reporting year. Under the proposed approach, the WEC obligated party would be responsible for any WEC obligation from facilities for which it was the facility owner or operator as of December 31 of the reporting year. The EPA recognizes that facilities may be acquired or divested at any time in the year, and that under the proposed approach the year-end owner or operator would be responsible for data and any corresponding WEC obligation for the entire reporting year. The EPA believes that this approach is both reasonable and necessary for implementation of the WEC program. First, subpart W data reporting uses the same approach; the facility owner or operator as of December 31 is responsible for emissions for the entire year. Because the subpart W data is inextricably linked to the WEC filing, it would be inappropriate to have different facility owners or operators under each regulation. Specifically, different owners or operators for the same facility under subpart W and the WEC program could lead to challenges for WEC filings and associated data verification, and increase industry burden by requiring significant coordination between different companies. Second, subpart W data are reported on an annual basis, and there is no means by which methane emissions could be accurately allocated across multiple owners or operators in a single year. For example, emissions could not be pro-rated based on time of ownership over the reporting year because emissions do not occur uniformly over time, and emissions from certain sources cannot be linked to specific times. Similarly, there is not a direct relationship between methane emissions and oil and natural gas production, so temporal data on hydrocarbon production could not be used to accurately allocate emissions. The EPA therefore believes it would be neither practical nor accurate for the reporting responsibility and potential WEC obligation for a single facility to be split among multiple WEC obligated parties.

The EPA also recognizes that a facility’s owner or operator, and thus its WEC obligated party, may change between December 31 and March 31. In such situations, under the proposed approach the WEC obligated party associated with a facility as of December 31 would remain responsible for accounting for that facility in its WEC filing and be responsible for any WEC obligation associated with that facility.

The EPA invites comments on these proposed definitions and whether additional definitions would help with the implementation of the WEC. The EPA requests comment on the proposed definition of WEC obligated party being responsible for all facilities for which it was the facility owner or operator as of December 31, regardless of when in the reporting year it became a facility’s owner or operator. The EPA requests comment on alternative definitions of

WEC obligated party, including those that would allocate facility subpart W data to multiple WEC obligated parties and a definition that would place the WEC obligation and reporting requirements on the WEC obligated party that was a facility’s owner or operator at the time of the WEC filing (i.e., as of March 31 of the year following the reporting year rather than December 31 of the reporting year). For alternative definitions that would allocate subpart W data, the EPA requests comment on potential methodologies that would accurately split the annual subpart W data across multiple WEC obligated parties.

B. Waste Emissions Thresholds

The CAA establishes a waste emissions threshold that is defined in terms of industry segment-specific methane intensity thresholds applicable to certain facilities that report GHG emissions under subpart W of the GHGRP. The industry segment-specific methane intensity thresholds specified in CAA 136(f) and listed in Table 2 of this preamble are based on a rate of methane emissions per amount of natural gas or oil sent to sale from or through a facility. The industry segment-specific methane intensity thresholds are generally defined in terms of a percentage of throughput (*e.g.*, 0.002 percent of natural gas sent to sale). However, since the WEC is based on metric tons of methane (*e.g.*, $900/metric ton) that exceed the threshold, for the purposes of calculating the number of metric tons that are subject to the WEC, we are proposing to calculate the facility waste emissions thresholds in metric tons of methane.

For the onshore and offshore petroleum and natural gas production industry segments, CAA section 136(f) differentiates based on whether the facility is sending natural gas to sale or only sending oil to sale, and if the facility does not send natural gas to sale, the threshold is based on methane emissions per amount of oil sent to sale. For facilities that are not in the onshore or offshore production industry segments, the industry segment-specific methane intensity thresholds are based on the amount of natural gas sent to sale from or through the facility. The industry segment-specific methane intensity thresholds are applied to the natural gas or petroleum throughput attributable to that industry segment to calculate facility-specific waste emissions thresholds. See Table 2 for an overview of how the waste emissions thresholds are calculated. Facility waste emissions thresholds are compared to reported methane emissions; facilities with methane emissions that exceed the waste emissions threshold may be subject to the WEC. For WEC applicable facilities under common ownership or control of a single WEC obligated party, the WEC applicable emissions for each facility are summed to calculate the net emissions for that WEC obligated party.

Subpart W requires reporting of natural gas throughput by thousand standard cubic feet, oil by barrels, and methane by metric ton. As a practical matter, since the WEC is based on a dollar per metric ton of methane, the waste emissions thresholds must generally be converted into metric tons of methane for comparison against reported methane, generally by multiplying the thresholds by the density of methane.

Table 2. Industry Segment Throughput Metrics and Methane Intensities

Industry Segment	**Throughput Metric** [a]	**Industry Segment-Specific Methane Intensity**
Onshore petroleum and natural gas production	The quantity of natural gas produced from producing wells that is sent to sale in the calendar year, in thousand standard cubic feet; or the quantity of crude oil produced from producing wells that is sent to sale in the calendar year, in barrels, if facility sends no natural gas to sale	0.20 percent of natural gas sent to sale from facility; or 10 metric tons of methane per million barrels of oil sent to sale from facility, if facility sends no natural gas to sale
Offshore petroleum and natural gas production		
Onshore petroleum and natural gas gathering and boosting	The quantity of natural gas transported through the facility to a downstream endpoint such as a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, a storage facility, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet	0.05 percent of natural gas sent to sale from or through facility
Onshore natural gas processing	The quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year, in thousand standard cubic feet	
Onshore natural gas transmission compression	The quantity of natural gas transported through the compressor station in the calendar year, in thousand standard cubic feet	0.11 percent of natural gas sent to sale from or through facility
Onshore natural gas transmission pipeline	The quantity of natural gas transported through the facility and transferred to third parties such as LDCs or other transmission pipelines in the calendar year, in thousand standard cubic feet	
Underground natural gas storage	The quantity of natural gas withdrawn from storage and sent to sale in the calendar year, in thousand standard cubic feet	
LNG import and export equipment	For LNG import equipment, the quantity of LNG imported that is sent to sale in the	0.05 percent of natural gas sent to

	calendar year, in thousand standard cubic feet; for LNG export equipment, the quantity of LNG exported that is sent to sale in the calendar year, in thousand standard cubic feet	sale from or through facility
LNG storage	The quantity of LNG withdrawn from storage and sent to sale in the calendar year, in thousand standard cubic feet	

[a] Throughput metrics in this table are based on the proposed subpart W reporting elements in the 2023 Subpart W Proposal (88 FR 50282).

1. Facility Waste Emissions Thresholds

CAA section 136(f)(1) through (3) establishes facility-specific waste emissions thresholds above which the EPA must impose and collect the WEC. The CAA defines waste emissions threshold requirements, and establishes the method for calculation of the charge, for nine segments of the oil and gas industry.

CAA section 136(f)(1) requires the EPA to impose and collect the WEC on facilities in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments with methane emissions, in metric tons, that exceed either 0.20 percent of the natural gas sent to sale from the facility or, if no natural gas is sent to sale, 10 metric tons of methane per million barrels of oil sent to sale from the facility. To determine the waste emissions threshold from a WEC applicable facility in the onshore petroleum and natural gas production and the offshore petroleum and natural gas production industry segments, the EPA is proposing two equations based on whether the facility sends natural gas to sale, which reflect the statutory text at 136(f)(1)(A) and (B). For onshore and offshore petroleum and natural gas production WEC applicable facilities that send natural gas to sale, we are proposing to use equation B-1 of 40 CFR 99.20(a). This equation multiplies the annual quantity of natural gas sent to sale from a WEC applicable facility by 0.002 (*i.e.*, 0.20 percent) and the density of methane (0.0192 metric tons per thousand standard cubic feet).[18] For onshore and offshore petroleum and natural gas production facilities that have no natural gas sent to sale, we are proposing to use equation B-2 of 40 CFR 99.20(b). Similar to proposed equation B-2, the annual quantity of oil sent to sale from a WEC applicable facility would be multiplied by 10 metric tons of methane per million barrels of oil. [19]

For WEC applicable facilities in the onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, LNG import and export equipment, and LNG storage industry segments, CAA section 136(f)(2) requires the EPA to impose and collect WEC on facilities with reported methane emissions, in metric tons, that exceed 0.05 percent of the natural gas sent to sale from or through such facility. To determine the waste emissions threshold from a WEC applicable facility in these industry segments, we are proposing to use equation B-3 under

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[18] Equation B-1 reflects the statutory text at 136(f)(1)(A), which states: “With respect to imposing and collecting the charge under subsection (c) for an applicable facility [in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments], the Administrator shall impose and collect the charge on the reported metric tons of methane emissions from such facility that exceed (A) 0.20 percent of the natural gas sent to sale from such facility…” 42 U.S.C. 7436(f)(1)(A).

[19] Equation B-2 reflects the statutory text at 136(f)(1)(B), which states: “With respect to imposing and collecting the charge under subsection (c) for an applicable facility [in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments], the Administrator shall impose and collect the charge on the reported metric tons of methane emissions from such facility that exceed… (B) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale.” 42 U.S.C. 7436(f)(1)(B).

40 CFR 99.20(c). This equation would multiply the annual quantity of natural gas sent to sale from or through a WEC applicable facility by 0.0005 (*i.e.*, 0.05 percent) and the density of methane (0.0192 metric tons per thousand standard cubic feet) to determine the facility-level waste emissions threshold.[20] The EPA notes that certain facilities in the gathering and boosting and natural gas processing industry segments may have zero throughput values using the proposed approach, because these facilities either receive no natural gas, or process or dispose of natural gas received, in a manner that results in sending zero quantities of natural gas to sale. Treatment of these facilities is discussed in section II.B.6. of this preamble.

CAA section 136(f)(3) requires the EPA to impose and collect WEC on WEC applicable facilities in the onshore natural gas transmission compression, onshore natural gas transmission pipeline, and underground natural gas storage industry segments with methane emissions, in metric tons, that exceed 0.11 percent of the natural gas sent to sale from or through such facility. We are proposing that equation B-4 under 40 CFR 99.20(d) be used to calculate the waste emissions threshold from a WEC applicable facility in these industry segments. Using proposed equation B-4 the EPA would multiply the annual quantity of natural gas sent to sale from or through a WEC applicable facility by 0.0011 (*i.e.*, 0.11 percent) and the density of methane

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[20] Equation B-3 reflects the statutory text at 136(f)(2), which states: “With respect to imposing and collecting the charge under subsection (c) for an applicable facility in [the onshore petroleum and natural gas gathering and boosting, onshore natural gas processing, LNG import and export equipment, and LNG storage industry segments], the Administrator shall impose and collect the charge on the reported metric tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facility.” 42 U.S.C. 7436(f)(2).

(0.0192 metric tons per thousand standard cubic feet) to determine the facility-level waste emissions threshold.[21]

The annual quantity of natural gas sent to sale from or through a facility reported under subpart W is reported in units of thousand standard cubic feet of natural gas per year, while facility methane emissions are reported in metric tons. The EPA is proposing to interpret the industry segment-specific methane intensity thresholds (*i.e.*, 0.20 percent, 0.05 percent, and 0.11 percent) indicated in CAA section 136(f)(1) through (3) to be in units of thousand standard cubic feet of methane of emissions per thousand standard cubic feet of natural gas. This requires reconciliation of methane emissions reported on mass basis and throughput reported on a volumetric basis. Because the waste emission charge is assessed using dollars per metric ton, the amount by which a facility is below or exceeding the waste emissions threshold must ultimately be converted to metric tons. The EPA’s proposed approach in equations B-1, B-3, and B-4 calculates facility waste emissions thresholds in metric tons by calculating the volume of gas at the given industry segment-specific methane intensity and then calculating what the mass of that volume would be if it were methane by multiplying by the density of methane (0.0192 metric tons per thousand standard cubic feet at standard temperature and pressure of 60° F and 14.7 psia). This allows the waste emissions threshold to be directly compared to reported metric tons

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[21] Equation B-4 reflects the statutory text at 136(f)(3), which states: “With respect to imposing and collecting the charge under subsection (c) for an applicable facility in [the onshore natural gas transmission compression, onshore natural gas transmission pipeline, and underground natural gas storage industry segments], the Administrator shall impose and collect the charge on the reported metric tons of methane emissions that exceed 0.11 percent of the natural gas sent to sale from or through such facility.” 42 U.S.C. 7436(f)(3).

of methane. The proposed approach is mathematically equivalent to, but simpler than, an approach that would convert reported methane emissions to volume, subtract a volumetric waste emissions threshold from that reported volume, and then convert the resulting value back to metric tons methane. The EPA notes that the proposed approach does not require information on the constituents or density of natural gas throughput.

As described in this section of the preamble, we are proposing to calculate waste emissions thresholds at the facility level, using the industry segment-specific methane intensity threshold given in CAA sections 136(f)(1) through (3), and the industry segment throughput reported under part 98, subpart W. The vast majority of facilities report as a single subpart W facility to a single subpart W industry segment. However, as discussed in section II.A. of this preamble, there are a small number of reporters that report as a single subpart W facility to multiple subpart W industry segments. Specifically, for facilities that report to multiple industry segments under a single subpart W facility, we are proposing in 40 CFR 99.20(e) that the facility-level waste emissions threshold is determined as the sum of the waste emissions thresholds for each industry segment that the facility operates within.

The EPA proposes to interpret “natural gas sent to sale” to mean the amount of natural gas sent to sale from a facility in the onshore or offshore petroleum and natural gas industry segments, as reported under subpart W. The EPA proposes to interpret “natural gas sent to sale from or through” to mean the natural gas throughput volume for a facility not in the onshore or offshore petroleum and natural gas industry segments that aligns with the movement of gas through a facility (*e.g.*, gas transported rather than gas received), as reported under subpart W.

For facilities in the onshore and offshore petroleum and natural gas production industry segments that do not send natural gas to sale, the EPA proposes to interpret “barrels of oil sent to sale” to mean the quantity of crude oil sent to sale, as reported under subpart W. The EPA is aware of other approaches for calculating “methane intensity” currently in use. These include methodologies that allocate total methane emissions between the petroleum and natural gas value chains and/or use methane rather than natural gas as the throughput value. CAA section 136(f)(1) through (3) refers to reported facility emissions and does not discuss allocation of emissions between petroleum and natural gas. With the exception of production facilities that only produce oil, the statutory text clearly lists natural gas as the throughput value. Further, the proposed approach can be implemented with data currently reported under subpart W, while alternative methane intensity methodologies would require reporting of additional data and increase the burden on the oil and gas industry. For example, an approach that calculates intensity as methane emissions divided by the methane in natural gas throughput would require facilities to collect and report additional information of the methane content of natural gas. An approach that calculates methane intensity as the mass of methane emissions divided by the mass of natural gas would require facilities to collect and report detailed information on all of the constituents of natural gas throughput. Finally, an approach that allocates methane emissions between the petroleum and natural gas value chains based on energy content would require facilities to collect and report detailed data on the constituents and energy content of all hydrocarbon throughput. The EPA therefore believes that the proposed approaches not only follow a plain reading of CAA section 136(f) but are also the best and most reasonable approaches.

The EPA invites comments on our proposed approach for calculating the waste emissions thresholds, particularly our proposed methodology and the underlying assumptions used to calculate the waste emissions threshold in metric tons of methane.

2. Facility Methane Emissions

To determine the total methane emissions from a WEC applicable facility, the EPA proposes to use facility-level methane data as reported under subpart W. On August 1, 2023, the EPA proposed revisions to subpart W consistent with the authority and directives set forth in CAA section 136(h) as well as the EPA’s authority under CAA section 114 (88 FR 50282). Facility methane emissions (and any emissions associated with exemptions from the WEC) would be calculated using methods and data required by subpart W for the emissions year covered by the annual WEC filing. For example, for the first year of the WEC (2024 emissions), WEC calculations would be based on the Subpart W requirements effective in 2024, and emissions year 2025 emissions and beyond would be based on Subpart W requirements effective in 2025 or any future revisions. The proposed approaches for calculating waste emissions thresholds and facility methane emissions align with the text of CAA section 136(f). CAA section 136(f)(1) through (3) states that the WEC is to be calculated based “on the reported metric tons of methane emissions from such facility that exceed” specified percentages of the “natural gas sent to sale from such facility” or “natural gas sent to sale from or through such facility” (or for onshore and offshore petroleum facilities that do not send gas to sale, "ten metric tons of methane per million barrels of oil sent to sale from such facility”). The EPA proposes to interpret “reported metric tons of methane emissions” to mean all reported methane emissions from a facility, as reported under subpart W. This value is an input to equation B-6.

3. Facility WEC Calculation

To calculate the amount by which a WEC applicable facility is below or exceeding the waste emissions threshold, the EPA proposes to use equation B-6 of 40 CFR 99.21, in which the facility waste emissions threshold, as determined in 40 CFR 99.20, is subtracted from facility total methane emissions. This calculation results in a value of metric tons of methane, the total facility applicable emissions, that is negative for facilities below the waste emissions threshold and positive for facilities exceeding the waste emissions threshold. The remainder of proposed 40 CFR 99.21 describes how to determine the WEC applicable emissions below or exceeding the waste emissions threshold considering any exemptions that may apply for WEC applicable facilities with total facility applicable emissions greater than 0 mt CH_4 (see section II.D. of this preamble for more information on the exemptions). As discussed in section II.C.2.b. of this preamble, the EPA proposes that WEC applicable facilities receiving the regulatory compliance exemption would be exempted from the WEC, and therefore would have zero WEC applicable emissions. For facilities in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments with total facility applicable emissions greater than 0 mt CH_4, any methane emissions associated with applicable exemptions would be subtracted to calculate WEC applicable emissions. For all other facilities, facility applicable emissions would equal WEC applicable emissions (unless the facility was receiving the regulatory compliance exemption).

The EPA invites comments on the proposed approach for calculating WEC applicable emissions.

4. Netting

The metric tons of methane emissions equal to, below, or exceeding the waste emissions threshold, or WEC applicable emissions, for each WEC applicable facility would be determined as specified in 40 CFR 99.21. CAA section 136(f)(4) allows for the netting of emissions at facilities below the waste emissions thresholds with emissions at facilities exceeding the waste emissions thresholds for facilities under common ownership or control within and across all applicable industry segments identified in 136(d). The EPA proposes to implement netting using equation B-8 at 40 CFR 99.22. Equation B-8 would sum the WEC applicable emissions from all WEC applicable facilities under the common ownership of control of a WEC obligated party to calculate net WEC emissions for that WEC obligated party. The EPA’s proposed interpretation of common ownership and control and definition of WEC obligated party are discussed in section II.C. of this preamble.

5. Waste Emissions Charge Calculation

CAA section 136(e) establishes annual $/metric ton charges for all methane emissions from WEC applicable facilities exceeding the waste emissions thresholds. The EPA proposes that a WEC obligated party’s total annual WEC, or WEC obligation, would be calculated by multiplying its net WEC emissions, as determined by proposed Equation B-8, by the annual $/metric ton charge. WEC obligated parties with net WEC emissions less than or equal to zero would not have a WEC obligation. WEC obligated parties with net WEC emissions greater than zero would have a WEC obligation and be required to pay a waste emissions charge. WEC obligation calculations would be made for calendar years 2024, 2025, 2026, and each year thereafter as per proposed 40 CFR 99.23.

6. Gathering and Boosting and Processing Facilities with Zero Reported Throughput

The EPA is aware of a small number of gathering and boosting and natural gas processing facilities that emit methane and report under subpart W, but do not send gas to sale. As a result, these facilities would report zero natural gas volumes for the throughput metrics used in the proposed waste emissions threshold calculations. For the gathering and boosting industry segment, these may be facilities that receive natural gas but then reinject it underground or otherwise do not transport any natural gas. For the processing industry segment, these may be fractionation plants that only receive and process natural gas liquids (NGLs) and do not handle natural gas. Under the proposed approach, all reported methane emissions from facilities with no reported throughput would be considered to be exceeding the waste emissions threshold. The EPA notes that the proposed approach is based on a plain reading of the statutory text; because these facilities would have a calculated waste emissions threshold of zero, all reported methane would by default be exceeding the threshold. The EPA requests comment on the treatment of gathering and boosting and natural gas processing facilities that do not report any volumes for the proposed WEC throughput metrics. The EPA requests comment on the proposed approach that would consider all reported methane from these facilities to be above the waste emissions threshold. The EPA also requests comment on an alternative approach that would consider all reported methane emissions from these facilities to be below the waste emissions threshold.

C. Common Ownership or Control for Netting of Emissions

1. EPA Interpretation and Proposal to Implement “Common Ownership or Control” for the Purposes of Part 99

CAA section 136(f)(4) allows WEC applicable facilities under “common ownership or control” to net “emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments” listed in section 136(d) and as defined in subpart W. The EPA interprets this to mean that for all eligible WEC applicable facilities under common ownership or control, the amount of metric tons of methane below the waste emissions thresholds (*i.e.*, the difference between emissions equal to the waste emissions threshold and reported emissions) at facilities below the waste emissions threshold may be used to net against the amount of metric tons of methane emissions that exceed the waste emissions thresholds at facilities above the waste emissions threshold. For the purposes of establishing common ownership or control under CAA section 136(f)(4), the EPA proposes to define “WEC obligated party” in 40 CFR 99.2. The EPA proposes that each subpart W facility would be associated with a single WEC obligated party (though each WEC obligated party may be associated with multiple subpart W facilities), which would be reported under the proposed requirements at 40 CFR 99.7. As discussed in section II.B.4. of this preamble and proposed in 40 CFR 99.22, all WEC applicable facilities associated with a common WEC obligated party would be able to net emissions for the purposes of calculating the WEC obligated party’s net emissions and total WEC obligation.

The EPA proposes that the WEC obligated party be the subpart W facility “owner or operator” as reported under 40 CFR 98.4(i)(3). The EPA proposes definitions for facility “owner” and “operator” that are applicable to the offshore petroleum and natural gas production, onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG import and export equipment, and LNG storage industry segments at 40 CFR 99.2. The onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and onshore natural gas transmission pipeline industry segments each have separate definitions for facility “owner or operator” proposed at 40 CFR 99.2. These proposed definitions are identical to the corresponding definitions in 40 CFR part 98; the EPA proposes that the owner or operator associated with a subpart W facility as reported under 40 CFR 98.4(i)(3) (regarding the list of owners or operators of the facility for the certification of representation of the designated representative) would also be the WEC obligated party for that facility. The EPA believes that the proposed approach for using facility owner or operator for the purpose of defining common ownership or control aligns with a plain reading of the statutory text. CAA section 136(c) states that a charge on methane emissions that exceed the waste emissions threshold shall be imposed and collected “from an owner or operator of an applicable facility.” Further, in the context of required revisions to the subpart W methodologies used to calculate methane emissions, CAA section 136(h) states that those revisions must be made to “allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.” Thus, CAA section 136(c) requires the charge to be imposed and collected on a facility owner or operator, and CAA section 136(h) presumes that owners and operators are responsible for submitting empirical data. Furthermore, since the list of owners or operators for each facility is directly reported under 40 CFR 98.4(i)(3), an established program at the time that Congress drafted CAA section 136, the EPA proposes that under the best reading of the statutory text, the facility owner or operator would be used as the entity for establishing common ownership or control of subpart W facilities within and across all applicable subpart W industry segments.

Although the EPA believes that the owner or operator approach is the most appropriate for netting under WEC, we seek comment on an alternative approach that would use the parent company of a facility’s owner or operator for the WEC obligated party and determining common ownership or control of facilities. For each subpart W facility, the facility owner or operator and parent company are reported under 40 CFR 98.4(i)(3) and 40 CFR 98.3(c)(11), respectively. The parent company represents the highest-level company based in the United States with an ownership interest in the facility. For parent company reporting, the percent ownership in the facility is also reported under 40 CFR 98.3(c)(11). Because a parent company has an ownership interest in a subpart W facility, multiple facilities may be said to be owned by the same parent company and might also be considered as being under common ownership or control of that parent company. So, one difference between using the owner or operator rather than a parent company for establishing common ownership or control is the number of facilities that may be brought under common ownership or control in each approach. For most facilities, the reported owner or operator is a subsidiary of the reported parent company. A single parent company may have multiple different owners or operators (*i.e.*, subsidiaries) associated with facilities within and across subpart W industry segments. For example, an onshore petroleum and natural gas production facility and onshore natural gas processing facility owned by the same parent company may each have a different owner or operator. The number of "common" facilities is usually higher when the parent company is used, and lower when the owner or operator is used. The parent company approach would therefore provide a broader interpretation of common ownership or control relative to use of owner or operator. However, it is important to note that at the time CAA section 136 was enacted in 2022, the term "common ownership or common control" was a term used in the subpart W regulations. Under the subpart W regulations, the EPA has used the term "common ownership or control" to refer to the owner or operator, not to the parent company. Congress was likely aware of this definition when it enacted section 136. Therefore, the EPA is proposing to use facility owner or operator for the purpose of establishing common ownership or control based on a plain reading of CAA section 136(c), and believes that this is the better reading of the text in context with subpart W. However, the EPA requests comment on both the proposed approach using facility owner or operator and on an alternative approach using facility parent company for determining common ownership or control of WEC applicable facilities.

In some cases, a WEC applicable facility may have multiple owners or operators reported under 40 CFR 98.4(i)(3). In these situations, the EPA proposes that the facility owners or operators would designate one of the owners or operators as the WEC obligated party for that facility, as proposed in 40 CFR 99.4. Under the proposed approach, the process for selection of the WEC obligated party at facilities with multiple owners or operators would be similar to the approach for selecting a designated representative under 40 CFR part 98. This process would require selection of a single WEC obligated party for the facility by an agreement binding on each of the owners or operators associated with the facility. The proposed approach for facilities with multiple owners allocates all facility-level methane emissions below or exceeding the waste emissions thresholds to a single WEC obligated party. We request comment on the proposed approach of allocating all methane emissions below or exceeding the waste emissions thresholds from a facility with multiple owners or operators to a single WEC obligated party. We request comment on other approaches that could be used to allocate emissions to owners or operators at facilities with multiple owners or operators. We request comment on the proposed approach of requiring the group of facility owners or operators to determine which owner or operator is the WEC obligated party, and alternative approaches for designating the WEC obligated party, at facilities with multiple owners or operators.

The EPA also evaluated an approach that would allocate facility methane emissions below or exceeding the waste emissions thresholds at facilities with multiple owners to parent companies based on their reported percent ownership in the facility. Some subpart W facilities with multiple owners have parent companies with very small (*i.e.*, less than one percent) equity shares. The minority owners may include individuals and small oil and gas companies with no operational control over the facility. Allocating methane emissions below or exceeding the waste emissions thresholds based on facility ownership would expose a larger number of individuals and small companies to potential WEC obligations. We note that allocating methane emissions from facilities with multiple owners to each owner based on facility ownership would only be possible using a parent company approach and not using the proposed owner or operator approach because GHGRP reporting does not currently include data on owner or operator facility equity share or include direct linkages between owners or operators and parent companies that could be used to assign facility ownership percentages to owners or operators. There may also be situations in which the facility owner or operator is a third-party operator with no ownership in the facility either directly or through their parent company.

We request comment on an alternate approach that would allocate methane emissions to parent companies using percent ownership in the facility as well as other possible allocation methodologies for facilities with multiple parent companies. We request comment relevant to understanding other appropriate approaches for allocating emissions from a facility with multiple parent companies or owners or operators to a single WEC obligated party or multiple WEC obligated parties. For example, how are costs allocated at such facilities, and are they usually shared by parent companies (*e.g.*, based on percent ownership in the facility), entirely borne by the facility operator, or does cost sharing vary based on facility-specific contractual agreements?

2. Facilities Eligible for the Netting of Emissions

The EPA’s proposed implementation of CAA section 136(f)(4) would define which types of applicable subpart W facilities are eligible to net emissions. We propose to establish netting eligibility criteria based on a facility’s total reported subpart W GHG emissions, status in relation to the regulatory compliance exemption, and overall regulated status under the GHGRP. In our proposed approach to netting, we chose interpretations which were the most consistent with a plain reading of the CAA, as well as the most transparent and straightforward to implement. As described in more detail in the following sections, our approach assumes that if a facility's emissions are not subject to the WEC, either because the facility is not a WEC applicable facility, or because a WEC applicable facility receives the regulatory compliance exemption, that facility's emissions do not factor into the netting of emissions for a WEC obligated party. In other words, only WEC applicable facilities may net, and only WEC applicable emissions may be netted. As will be explained further in section II.C.2.a. of this preamble, we believe this interpretation is consistent with CAA section 136(f)(4) "the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments identified in subsection (d)," since the reference to "applicable thresholds" and "applicable segments", which reflect other subsections under CAA section 136, implies that only WEC applicable emissions should be considered in the netting calculation. We note that for applicable facilities with unreasonable delay or plugged well exemptions, under the proposal, emissions associated with these exemptions would be removed from any emissions exceeding the waste emissions threshold prior to netting calculations.

a. Facilities Required to Report to GHGRP and That Have Subpart W Emissions Greater Than 25,000 Metric Tons of CO_2e

In accordance with CAA section 136(c) and the proposed definition of "WEC applicable facility" in 40 CFR 99.2, we are proposing that subpart W facilities that have subpart W emissions greater than 25,000 mt CO_2e are eligible for netting, with the exception of those that are receiving the regulatory compliance exemption (as discussed in section II.D.2. of this preamble). Facilities that report less than 25,000 mt CO_2e under subpart W are not subject to the WEC, and the EPA proposes that such facilities would not be eligible for netting. These types of facilities are discussed in greater detail in section II.C.2.c. of this preamble. The EPA's proposed approach follows what the agency considers to be the best reading of the plain text of, and the relationship between CAA sections 136(d), 136(c), and 136(f) (which includes subsections 136(f)(4) and 136(f)(1)-(3)). The following sections will provide an overview of the relevant statutory text, and the corresponding basis for the EPA's belief that only WEC applicable facilities may net, and only WEC obligated emissions may be netted, under CAA section 136(f)(4).

CAA section 136(d) introduces the nine industry segments within which all subpart W facilities must fall in order to be evaluated for WEC applicability. Importantly, facilities within these segments are “applicable facilities”, per CAA section 136(d), but they are not necessarily “WEC applicable facilities”, subject to possible WEC obligation, unless they report over 25,000 mt CO_2e per year under subpart W. CAA section 136(c) clarifies this point. Specifically, CAA section 136(c) requires the Administrator to impose and collect a charge on the owner or operator “of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W”. Thus, building upon the CAA section 136(d) definition, CAA section 136(c) establishes that only facilities which both fall within one or more of the nine CAA section 136(d) industry segments *and* report more than

25,000 mt CO_2e under subpart W are subject to the WEC program. For clarity, in this rulemaking the EPA refers to these facilities as "WEC applicable facilities".

CAA section 136(f), which is entitled "Waste Emissions Threshold", includes a series of subsections under this heading. Subsections 136(f)(1)-(3) illustrate the meaning of "waste emissions threshold" in this context, and explain that these are actually a series of thresholds which determine when and how to impose a charge on methane emissions from WEC applicable facilities, depending on which industry segment or segments they fall under. Specifically, the nine CAA section 136(d) industry segments are categorized into four groups, and a waste emissions threshold is applied to each of the four. CAA section 136(f)(1) covers offshore and onshore petroleum and natural gas production (industry segments (1) and (2) under CAA section 136(d)), and further divides this category depending on whether or not natural gas is sent to sale: "With respect to imposing and collecting the charge under subsection (c) for an applicable facility in an industry segment listed in paragraph (1) or (2) of subsection (d), the Administrator shall impose and collect the charge on the reported metric tons of methane emissions from such facility that exceed (A) 0.20 percent of the natural gas sent to sale from such facility; or (B) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale."[22]

CAA sections 136(f)(2) and (3) follow the same model: section 136(f)(2) establishes thresholds for nonproduction petroleum and natural gas systems (industry segments (3), (6), (7),

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[22] 42 U.S.C. at 7436(f)(1).

and (8) under section 136(d)[23]), and imposes a charge on "the reported metric tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facility"[24]; and section 136(f)(3) establishes thresholds for natural gas transmission (industry segments (4), (5), and (9)[25]) and imposes a charge on "the reported metric tons of methane emissions that exceed 0.11 percent of the natural gas sent to sale from or through such facility."[26] But each industry-specific threshold is introduced in the same way: "With respect to *imposing and collecting the charge under subsection (c) for an applicable facility in an industry segment listed* in paragraph (x) of subsection (d), [charges shall be imposed as follows]". Following this plain text, it is clear that the CAA section 136(f) waste emission thresholds apply *only to WEC applicable facilities* – that is, facilities within one or more of the nine WEC industry segments listed in CAA section 136(d) which emit more than 25,000 mt per year CO_2e under subpart W, and thus may be subject to charge under CAA section 136(c).

Finally, in the netting provision itself, CAA section 136(f)(4), states that "in calculating the total emissions charge obligation for facilities under common ownership or control, the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all

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[23] Specifically: (3) onshore natural gas processing; (6) liquefied natural gas storage; (7) liquefied natural gas import and export equipment; and (8) onshore petroleum and natural gas gathering and boosting.

[24] *Id.* at section 7436(f)(2).

[25] Specifically, (4) onshore natural gas transmission compression; (5) underground natural gas storage; and (9) onshore natural gas transmission.

[26] *Id.* at section 7436(f)(3).

applicable segments identified in subsection (d)". As noted above, the EPA is proposing that this netting provision applies to WEC applicable facilities and WEC applicable emissions only, for three compelling reasons.

First, the EPA believes that per the best reading of the statute, the term "applicable thresholds" refers to the waste emission thresholds outlined in CAA section 136(f)(1)-(3). This is important because, as noted above, the waste emissions thresholds apply *only* to WEC applicable facilities – they determine whether, and how, a charge shall be imposed on methane emissions from a facility which has already been triggered into the WEC program by virtue of its 25,000 mt per year CO_2e in subpart W. The thresholds do not apply to facilities which emit fewer than 25,000 mt per year of CO_2e under subpart W, because under CAA section136(c), no charge may be imposed or collected on such facilities. Facilities which emit less than 25,000 mt per year of CO_2e under subpart W may emit any amount of methane, but these methane emissions are not WEC applicable emissions: they cannot be evaluated according to the waste emissions thresholds, and they cannot be considered to fall either above or below these thresholds. Thus, in "*account[ing] for facility emissions levels that are below the applicable thresholds*", the EPA understands that it must account for WEC applicable emissions from WEC applicable facilities which fall below the waste emissions thresholds, and produce a negative value under Equation B-6 (see above at section II.B.3.).

As previously stated, EPA's conclusion that the term "applicable thresholds" in CAA section 136(f)(4) refers to the waste emissions thresholds outlined in CAA section 136(f)(1)-(3) is supported by both the text and structure of the statute. First, the structure of the statute strongly supports the presumption that CAA section 136(f)(4) refers to netting based on a facility's relationship to the waste emissions thresholds because CAA section 136(f)(4) appears as part of CAA section 136(f), under the "waste emissions threshold" heading, and immediately following CAA section 136(f)(1)-(3)'s establishment of the specific waste emissions thresholds for each industry segment. It follows that CAA section 136(f)(4)'s reference to "applicable thresholds" refers to these industry segment-specific requirements, and accordingly "applicable segments" refers to the industry segments identified in CAA section 136(f)(1)-(3).

A close reading of the text also strongly supports our presumption regarding the waste emissions thresholds, because CAA section 136(f)(4) refers to facility emissions levels that are "below the *applicable thresholds*," plural. The use of the plural, and the use of the term "applicable," both indicate that Congress was referring here to the multiple waste emissions thresholds introduced in CAA sections 136(f)(1) through (3), which specifically and separately apply to WEC applicable facilities within various subsets of industry segments, defined in CAA section 136(d). Again, these separate thresholds *only* apply to WEC applicable facilities, which emit over 25,000 tons per year of CO_2e per year.

In addition to the "applicable thresholds" question, the EPA believes that Congress's use of the term "applicable segments" in stating that EPA may "redu[ce] the total obligation to account for facility emissions levels that are below the applicable thresholds *within and across all applicable segments identified in subsection (d)*," is significant here. While CAA section 136(d) introduces the nine relevant "industry segments" within which all WEC applicable facilities must fall, CAA section 136(f)(4) classes these segments into four groups, and is the only provision to use the term "applicable segments". As noted above, CAA section 136(f) establishes a set of requirements determining when and how to impose a charge on those facilities triggered into the program, depending on their industry segment and the amount of methane they emit. It follows that CAA section 136(f)(4)'s reference to "applicable thresholds" refers to these four group-specific thresholds, and "applicable segments" refers to the nine segments within the four segment groups. In other words, each group of segments constitutes the "applicable" segments to their corresponding applicable threshold. This is important, again because the four groups laid out under CAA section 136(f) include only WEC applicable facilities.

Finally, Congress's statement that netting shall be employed "in calculating the total emissions charge obligation for facilities under common ownership or control", further indicates that only WEC applicable facilities may be netted. Logic indicates that only WEC applicable facilities, with WEC applicable emissions, would be relevant to a determination of total emissions charge obligation. As regards the WEC program, WEC obligated parties are concerned with methane emissions for the WEC applicable facilities for which they are responsible – not various other subpart W facilities for which a WEC charge can never be imposed. Accordingly, the EPA believes that under the best reading of this provision WEC obligated parties may net WEC applicable methane emissions between facilities in different segments, as long as all facilities are WEC applicable facilities.

b. Facilities With Subpart W Emissions Greater Than 25,000 Metric Tons of CO_2e That Are Receiving the Regulatory Compliance Exemption

The EPA proposes that during such time that a facility receives the regulatory compliance exemption, that facility would have zero WEC applicable emissions and thus would not be able to participate in the netting of methane emissions across facilities under common ownership or control of a WEC obligated party. The EPA’s proposed approach is based on a plain reading of the statutory text, and follows the same reasoning outlined in section II.C.2.a. of this preamble, which explains that under the best reading of the text, only WEC applicable facilities may net.. This section will further expand upon EPA reasoning that only WEC applicable emissions may be netted, and clarify this point for purposes of the regulatory compliance exemption.

CAA section 136(f)(6)(A) states that “[c]harges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111” if specific criteria are met (these criteria are discussed in section II.D.2. of this preamble). The EPA’s interpretation of the regulatory compliance exemption is that, for a WEC applicable facility meeting the exemption criteria, the entire facility is exempted, and therefore the facility does not generate WEC-applicable emissions. In order to net, facilities must be WEC applicable facilities (they must emit over 25,000 CO_2e per year under subpart W) and they must also generate WEC applicable emissions (methane emissions below or above the WEC emissions thresholds *that are subject to charge*.) Again, this follows from the text. Section 136(f)(4) applies “in calculating the total emissions charge obligation” only. Emissions which are subject to an exemption are by definition not subject to charge. WEC applicable emissions are only those emissions subject to charge under section 136(c). Because, under the proposed approach WEC applicable facilities with the regulatory compliance exemption would have zero WEC applicable emissions, these facilities would by default not be able to participate in netting (*i.e.*, they would have no emissions to net). The proposed approach of facilities with the regulatory compliance exemption having zero WEC applicable emissions allows for the practical implementation of the exemption within the broader framework of the proposed WEC calculations. Assigning exempted facilities zero WEC applicable emissions ensures that charges shall not be imposed on these facilities without interfering with netting calculations or removing facility-specific reporting elements necessary for WEC implementation. Such facilities would continue to be included in WEC filings reported under part 99 as long as they remain WEC applicable facilities. Further, if such facilities fall out of compliance such that the regulatory compliance exemption no longer applies and they again generate WEC applicable emissions, such facilities would again be included in netting.

The EPA notes that under the proposed approach, facilities with emissions below the waste emissions threshold would not receive the regulatory compliance exemption (see discussion in section II.D.2.f. of this preamble), and thus these facilities would always have WEC applicable emissions and would be able to participate in netting across facilities under common ownership or control.

The EPA requests comment on the proposed approach in which WEC applicable facilities receiving the regulatory compliance exemption would have zero WEC applicable emissions. The EPA requests comment on other options for WEC applicable facilities receiving the regulatory compliance exemption and their treatment in the context of netting.

c. Exclusion of Facilities Reporting 25,000 or Fewer Metric Tons of CO_2e to Subpart W of Part 98

Per CAA section 136(c), the WEC shall only be imposed on owners or operators of applicable facilities that report more than 25,000 mt CO_2e under subpart W. A large number of facilities that report under the GHGRP have subpart W emissions below 25,000 mt CO_2e. A part 98 subpart W facility is generally allowed to cease reporting or “offramp” due to meeting either the 15,000 mt CO_2e level or the 25,000 mt CO_2e level for the number of years specified in 40 CFR 98.2(i) based on the CO_2e reported, as calculated in accordance with 40 CFR 98.3(c)(4)(i) (*i.e.*, the annual emissions report value as specified in that provision). Some facilities have dropped below 25,000 mt CO_2e in total reported emissions to part 98 and are continuing to report while on the reporting offramp. Other facilities report emissions under multiple subparts (*e.g.*, subpart W and subpart C) and have total emissions equal to or greater than 25,000 mt CO_2e across both subparts, but subpart W emissions below 25,000 mt CO_2e. The latter category includes processing plants, transmission compressor stations, underground storage facilities, LNG storage facilities, and LNG import and export facilities that report their combustion emissions under subpart C. Many of these facilities have total GHGRP emissions exceeding 25,000 mt CO_2e, but subpart W emissions that alone fall below this threshold.

We are proposing that subpart W facilities with subpart W emissions equal to or below 25,000 mt CO_2e are not WEC applicable facilities and are therefore excluded from netting. This proposed approach aligns with a plain reading of the requirement in CAA section 136(c) that only applicable facilities with subpart W emissions exceeding 25,000 mt CO_2e are subject to the

WEC – facilities below this threshold are not subject to the WEC and therefore do not generate WEC applicable emissions and are not able to net emissions.

d. Exclusion of Facilities Not Required to Report to the GHGRP

Per CAA section 136(c) and (d), CAA section 136(f)(4), and the proposed definition of “WEC Applicable Facility” in 40 CFR 99.2, which reflects the statutory text at CAA section 136(d), we are proposing that facilities that are not required to report to the GHGRP, and thus are not WEC applicable facilities, would not be eligible for netting. Again following the reasoning outlined in section II.C.2.a. of this preamble, the EPA’s proposed approach is based on a plain reading of CAA section 136(f)(4), which states that netting is allowed within and across the nine subpart W industry segments identified in CAA section 136(d); section 136(d), which states that “applicable facility(ies)” are facilities within industry segments “as defined in subpart W”; and section 136(c), which states that the WEC is only applicable to subpart W facilities that report more than 25,000 CO_2e per year. Following the plain text, only facilities subject to subpart W may be evaluated as possible WEC applicable facilities, and only WEC applicable facilities (subpart W facilities emitting over 25,000 CO_2e) can have WEC applicable emissions that may be subject to charge. As explained in section II.C.2.a. of this preamble, only WEC applicable facilities may net, and only WEC applicable emissions may be netted. Further, CAA section 136(c) states that the WEC is only applicable to certain facilities that report under subpart W of the GHGRP.

D. Exemptions to the Waste Emissions Charge

1. Exemption for Emissions From Eligible Delays in Environmental Permitting Under CAA Section 136(f)(5)

CAA section 136(f)(5) establishes an exemption for emissions resulting from delay in environmental permitting by stating, “Charges shall not be imposed pursuant to paragraph (1) on emissions that exceed the waste emissions threshold specified in such paragraph if such emissions are caused by unreasonable delay, as determined by the Administrator, in environmental permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation.”

This provision would exempt from the charge certain emissions occurring at facilities in the onshore and offshore production segments. Paragraph (1) referenced in the exemption refers to CAA section 136(f)(1), which establishes the waste emissions threshold for applicable facilities in the production sector, as discussed in section II.B. of this preamble. The exemption is limited to emissions occurring as a result of certain delays in permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation. Infrastructure necessary for offtake would include gathering and transmission pipelines and compressor stations. Increased volume as a result of methane emissions mitigation implementation would include increased natural gas amounts available for transport that would have otherwise been emitted.

a. Emissions Eligible for the Permitting Delay Exemption

Given the complexity of defining and determining “unreasonable delay” related to environmental permitting, the EPA is proposing a simplified approach of establishing a set of four criteria for applying the unreasonable delay exemption established by CAA section 136(f)(5). These criteria would only apply in the context of determining eligible emission exemptions for the implementation of CAA 136(f)(5) and this proposed rulemaking; they are not intended to speak to the reasonableness of a permitting delay in any other context. The EPA understands that the issue of what constitutes an unreasonable delay is multi-faceted and may be quite different under different factual circumstances. At the same time, the EPA believes it is important in the context of this program to propose a definition that is both consistent with the statutory charge and administrable within the capabilities of the EPA. With those caveats in mind, the EPA proposes the following four criteria for implementing this exemption: (1) the facility must have emissions that exceed the waste emissions threshold; (2) neither the entity seeking the exemption, nor the entity responsible for seeking the permit, may have contributed to the delay; (3) the exempted emissions must be those (and only those) resulting from the flaring of gas that would have been mitigated without the permit delay, and the flaring that occurs must be in compliance with all applicable local, state, and Federal regulations regarding flaring emissions; and (4) a set period of months must have passed from the time a submitted permit application was determined to be complete by the applicable permitting authority.

The EPA believes this approach meets the Congressional intent of this exemption while creating a program that can be implemented annually allowing for collection of WEC in a timely manner. The proposed approach is intended to reduce burden on the companies and government compared with an approach that would not specify a timeframe or other criteria but would rely on decisions made on a case-by-case basis to determine whether the timing and other circumstances of an individual permitting action constitutes an unreasonable delay. We note, however, that these criteria outlined above, including the timeframe, are proposed for the purpose of defining the emissions eligible for an exemption for the purposes of the implementation of CAA 136(f)(5) and this proposed rulemaking only and are not applicable for defining an unreasonable delay outside of this context. The criteria introduced in this section do not apply to the determination of unreasonable delay for purposes of the National Environmental Policy Act (NEPA), the Administrative Procedure Act (APA), or any other law involved in permitting processes or any other agency actions. In particular, the timeline criterion should not be considered applicable or informative to the determination of unreasonable delay in any context other than determining emission exemptions for the implementation of CAA 136(f)(5) and this proposed rulemaking.

The first criterion, that the facility must have emissions that exceed the waste emissions threshold, is based on CAA 136(f)(5), which states that “charges shall not be imposed pursuant to paragraph (1) on emissions that exceed the waste emissions threshold specified in such paragraph if such emissions are caused by unreasonable delay.” A straightforward reading of this language limits the exemption to emissions exceeding the waste emissions threshold. In addition, since charges would not be imposed on emissions below the threshold, an exemption is unnecessary in cases where facility emissions are below the threshold. The EPA proposes that emissions from facilities that are below the waste emissions threshold would not be exempted. The EPA proposes that for facilities that exceed the waste emissions threshold, emissions eligible for the permitting delay exemption would be subtracted from the facility emissions that exceed the waste emissions threshold. The exempted emissions would not be used to reduce emissions totals below the threshold (*i.e.*, the lowest possible WEC applicable emissions for a facility with the exemption would be zero).

The second criterion relates to responsiveness on the part of the production sector WEC applicable facility reporting emissions caused by a delay in gathering or transmission infrastructure and the gathering or transmission infrastructure permit applicant: neither the entity potentially eligible for the exemption (*i.e.*, a WEC applicable facility in the onshore or offshore production sector) nor the entity seeking the environmental permit (*e.g.*, an entity seeking a permit for gathering or transmission infrastructure) has contributed to the delay in permitting.

The EPA is proposing that contributions to the delay by either the production entity potentially eligible for the exemption or the entity seeking the environmental permit would be determined based upon the timeliness of response to requests for additional information or modification of the permit application. Delays in response exceeding the response time requested by the permitting agency, or requested by the relevant production or gathering or transmission infrastructure entity seeking the permit, or responses that exceed 30 days from the request if no specific response time is requested, would be considered to contribute to the delay in processing the permit application. Note that this proposed determination of what would constitute a delay eligible for the exemption in environmental permitting would be specific solely to implementation of CAA section 136(f)(5) and this proposed rulemaking for part 99, and would not necessarily be applicable to any other section of the CAA, or any permitting program administered by the EPA or by a state or local permitting authority.

The third criterion is that the exempted emissions must be those resulting from the flaring of gas that would have been mitigated without the permit delay – and that exempted emissions must be in compliance with all applicable local, state, and Federal regulations regarding flaring emissions. The EPA believes that this approach reasonably follows from the text of section 136(f)(5), which exempts emissions caused by unreasonable delay in the permitting of "gathering or transmission infrastructure *necessary for offtake of increased volume as a result of methane emissions mitigation implementation*."[27] Following this statutory directive, the EPA is proposing that exempted emissions are flaring emissions which (1) would otherwise be captured in accordance with applicable regulations but (2) are not captured due to a delay in the permitting necessary for offtake. It is anticipated that operations seeking the exemption could include oil production sites planning to send gas to sale, rather than flaring the emissions, or facilities that produce natural gas, condensate or natural gas liquids and that expand operations and are flaring gas because a pipeline is not yet available. Only flaring emissions caused by the unreasonable delay in permitting, and occurring in compliance with all applicable regulations, would be exempt. Other emissions occurring at the wellsite would not be exempt because they are not associated with the delay or because they do not occur in compliance with applicable regulations. For example, fugitive emissions from leaks would occur with or without the delayed infrastructure, and venting emissions is widely restricted due to Federal, state, or local regulations on venting.

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[27] 42 U.S.C. 7436(f)(5) (emphasis added).

Flaring emissions that occur as a result of flaring that is not in compliance with applicable regulations are ineligible for the exemption. This approach accords with the text of section 136(f)(5), which states that the exemption is for emissions occurring as a result of unreasonable delay in permitting required for the build out of infrastructure “necessary for offtake of increased volume *as a result of* methane emissions mitigation.”[28] Regulations limiting flaring and venting will result in an increased volume of gas that must be captured and transmitted, compared with a circumstance without methane emissions mitigation implementation, in which gas is flared or vented on site. Thus, the EPA understands that this provision is designed to exempt flaring done in compliance with regulations, where sources are prepared to capture gas but cannot yet do so due to lack of offtake infrastructure. However, a delay in permitting does not allow exemption from other applicable local, state, and Federal regulations regarding flaring. Thus, the flaring emissions exempt under 136(f)(5) cannot exceed flaring emissions allowable under other applicable local, state, and Federal regulations.

The fourth criterion is that an eligible “unreasonable delay” would be a delay that exceeds a set period of months specified in the final rule. The EPA’s current assessment is that this time period would likely fall somewhere between 30 and 42 months from the date that a submitted permit application was determined to be complete by the relevant permitting authority. This time period is not tied to the timing of the WEC; a facility that meets all four criteria would be eligible for the exemption in the first year of the WEC if the time period requirement has been

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[28] 42 U.S.C. 7436(f)(5)

met. The relevant permitting authority could be the United States Federal Energy Regulatory Commission (FERC), or other federal, state or local agencies that issue environmental permits. The environmental permitting process can require multiple steps including, but not limited to: the entity preparing and submitting a permit application; the entity responding to comments with supporting information; the regulatory agency preparing a draft permit; public comment; and preparation and issuance of the final permit. Target dates for permit actions can vary by regulatory agency and depend, for example, on whether the relevant permit is for a new or existing source, or whether the action is a major or minor modification. The EPA is proposing to set a timeframe for unreasonable delay that is not specific to particular permitting actions or agency timelines.

The EPA is proposing to set a timeline somewhere in the range of 30 to 42 months, with the default to be specified in the final rule after consideration of comments received. This preliminary range is based on the EPA's current understanding of timelines for oil and gas permitting across Federal agencies. In particular, the preliminary range is informed by the EPA's review of data made available through the Federal Permitting Improvement Steering Council (FPISC) through Title 41 of the Fixing America's Surface Transportation Act (FAST-41). The "Recommended Performance Schedules for 2020" released by FPISC contains data for the Federal review and permitting of 18 pipeline projects under the FAST-41 program.[29] For these

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[29] Federal Permitting Improvement Steering Council, "2020 Recommended Performance Schedules." Federal Infrastructure Permitting Dashboard. April 6, 2020. *https://www.permits.performance.gov/fpisc-content/recommended-performance-schedules*. Accessed August 28, 2023.

projects, the mean time from receipt by FERC of a complete application to the issuance of a certificate of public convenience and necessity for interstate natural gas pipelines was 23 months, with three of the 18 projects (17 percent) exceeding 30 months. Criteria for inclusion in the FAST-41 program include projects that are considered likely to require investment exceeding $200,000,000 and that do not qualify for abbreviated review under applicable law; or projects of a size and complexity that the FPISC determines are likely to benefit from inclusion.[30] On this basis, the EPA believes the FAST-41 dataset may be a conservative population (*i.e.*, require more complex environmental review and permitting) when compared to the total of all gathering or transmission infrastructure projects.

The proposed range of 30 to 42 months also takes into account the 2023 Fiscal Responsibility Act, which set a limit under the National Environmental Policy Act of 1 year for completion of an Environmental Assessment and 2 years for completion of an Environmental Impact Statement unless extended by the lead agency in consultation with the applicant or project sponsor. However, the amount of time necessary to complete an Environmental Assessment or Environmental Impact Statement will vary depending on the specific agency action at issue, and this proposed timeline is not intended to reflect a determination of the reasonable length of a time necessary to complete such analysis in any specific instance. For projects requiring approval or permitting from a federal agency, completion of an Environmental

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[30] Federal Permitting Improvement Steering Council, "FAST-41 Fact Sheet." Federal Infrastructure Permitting Dashboard. September 13, 2022. *https://www.permits.performance.gov/documentation/fast-41-fact-sheet*. Accessed August 28, 2023.

Assessment or Environmental Impact Statement must occur prior to the agency taking a final agency action. Additional steps in the process that must be completed following completion of review under NEPA may add several months to the overall timeframe (*e.g.,* convening of FERC to approve or deny a certificate of public convenience and necessity).

We note that all four criteria must have been met for the EPA to determine that for the purpose of this exemption, emissions were caused by an unreasonable delay. No single factor, including timing, would be determinative as to whether a delay unreasonable in the context of this exemption. We are not assessing whether a delay of any particular period of months alone (i.e., in the absence of the other three criteria) should be considered unreasonable in the context of this exemption, and we are not assessing the reasonableness of a particular timeframe or collection of conditions outside of the context of this exemption specific to CAA section 136. An assessment of reasonableness in any other context depends on the circumstances specific to that context, which can vary considerably and there is no straightforward way to determine whether a delay is reasonable or unreasonable that applies to all contexts. We note that using the approach of requiring four criteria to be met may not fully capture case-by-case circumstances and therefore may not always produce the same determination as a more holistic evaluation would. We have proposed this approach of using four criteria, including one specifying a set timeframe, for the purposes of this exemption only to simplify this process, and for clarity and administrability; we understand that longer permitting timeframes are often not unreasonable in other contexts.

As an alternative to specifying that an “unreasonable delay” requires a set period of months to have elapsed since a permit application is deemed complete (in addition to the other three criteria), the EPA considered adopting a case-by-case process for determining whether an unreasonable delay in permitting has occurred. Under such an approach, the exemption for unreasonable delay could only be utilized by a facility that has obtained a facility-specific finding of unreasonable delay from the EPA. The EPA would evaluate documentation provided by a WEC obligated party to determine if there was an unreasonable delay. A WEC obligated party would not exclude emissions it claimed are associated with the unreasonable delay exemption until such time as it obtained an unreasonable delay finding from the EPA. In other words, emissions associated with a claim of unreasonable delay for which there is not an unreasonable delay determination by the EPA could not be subtracted from the emissions totals in the initial WEC filing. If the EPA subsequently were to make such a finding, the EPA would authorize a refund in accordance with its determination. Documentation could include information such as that currently proposed to be reported, such as information on mitigation activities, permitting timing, and regulations relevant to flaring, and information currently proposed as recordkeeping requirements, such as detailed records on responsiveness, in addition to other documentation specific to the relevant gathering or transmission infrastructure environmental permit, such as on the expected timing for the specific environmental permit(s) sought and the type of information that would be needed to support the claim that the permit(s) is delayed beyond what could be considered a reasonable timeframe. A case-by-case approach for reviewing and approving the unreasonable delay exemption would help ensure the validity of individual claims, and ensure that all applicable waste emissions for each facility are subject to charge, as directed by Congress. However, the EPA decided not to propose such an approach due to the time and resource burden that would be required to administer such a process, for both covered entities and for the EPA. We expect that many types of permitting situations can arise, with many permutations. If industry were required to demonstrate unreasonable delay on a case-by-case basis, the EPA anticipates this review process would result in uncertainty for industry and could lead to a significant backlog, thus making the annual calculation of the WEC unduly burdensome. Therefore, in the interest of simplicity and making the exemption available in an efficient manner and without significant additional burden, the EPA proposes to rely on this threshold of a set period of months, in addition to the three other criteria, which can be more easily applied without detailed investigation. The EPA notes that in its verification process under the proposed approach it would review the submitted documentation to confirm that requirements are met for each facility reporting an unreasonable delay, and facilities determined to have not met the requirements would be required to submit any additional owed WEC obligation and relevant penalties.

Section II.D.1.c. below details the reporting requirements for this exemption which provide information necessary for verification of the exemption eligibility and exempted emission quantities.

We seek comment on these four criteria, each required to be met to determine emissions eligible for the unreasonable delay exemption. We seek comment on the use of responsiveness to requests regarding permitting by the permit applicant or the production segment facility experiencing delayed mitigation as a criterion. We seek comment on the use of 30 days to assess responsiveness where a specific timeframe for response is not provided. We seek comment on the criterion that exempted emissions are those resulting from flaring of gas that would have been mitigated without the permit delay, and that only flaring emissions that are in compliance with applicable regulations are eligible. We seek comment on the appropriate timeframe to be used as part of the four-factor test proposed today – specifically, what would be the best period of time (even if it is below or above the 30-42-month range EPA is leaning towards now) to use as a trigger for assessing unreasonable delay for the purposes of CAA section 136(f). We seek comment on the proposed use of one timeframe for eligibility versus an approach that might use different time frames for different types of permits. We seek comment on whether specific types of delays should be eligible or ineligible, which could be included as additional criteria or used in place of all or some of the proposed criteria. For example, we seek comment on whether we should establish that delays due to litigation regarding pipeline development are ineligible. We also seek comment on an alternative case-specific approach in which each facility with exempt emissions from unreasonable delay would provide additional facility- and permit-specific information, and in which the exemption would not be granted unless approved by the EPA. Finally, we seek comment on whether EPA should include additional criteria when defining the unreasonable delay exemption. For example, we seek comment on whether, in addition to the four criteria, we should add a criterion that entities show the flaring is necessary (i.e., other options for beneficially use or reinject of gas were infeasible).

b. Calculation of Emissions Resulting From an Unreasonable Delay

Through the provisions proposed at 40 CFR 99.32, the EPA is proposing that exempted emissions are flaring emissions caused by the delay. We are proposing that exempted flaring emissions are the methane emissions (or a subset of the methane emissions) from flaring reported under subpart W.

To calculate the exempted emissions quantity, the entity must determine the time period associated with the emissions that occurred as a result of the delay within the filing year. The EPA is proposing that the delay begins when emissions would have been avoided through the operation of the gathering or transmission infrastructure, not when construction would begin, as in many cases the infrastructure would not be immediately in place and operational at the time of permitting approval. For example, a permit to construct might be needed before construction begins, and construction could take months or more before the infrastructure would be in place.

Where the exempted emissions cover the entire reporting year, the exempted flaring emissions would be the total reported to part 98 for flare stacks, associated gas flaring, and the portion of offshore methane emissions attributable to flaring. Where exempted emissions occur in only a fraction of a reporting year, the facility is to use data on flaring emissions over that time frame if available, and if unavailable, the facility is to adjust part 98 flaring emissions using the fraction of the year that the exemption is available. Where flared emissions impacted by permitting delay only account for a portion of the total flared emissions, the facility is to adjust their part 98 reported flaring emissions using company records and/or engineering calculations.

We seek comment on the provisions proposed, including the use of reported flaring emissions to determine exempted emissions, the use of part 98 data, and the approaches for quantifying emissions for fractions of the reporting year.

c. Reporting and Recordkeeping Requirements for the Exemption for Emissions Resulting from a Permit Delay

Through the provisions proposed at 40 CFR 99.31, the EPA is proposing that the WEC obligated party receiving the exemption would provide information on each well pad or offshore platform impacted by the delay. This includes the type of permit, permitting authority, and the date that the permit application was complete. The WEC obligated party must report the planned timing of the commencement of the offtake of gas had the permit not been delayed. This includes a listing of the methane emissions mitigation activities that are impacted by the delay and the flaring emissions associated with natural gas that would have been directed to gathering or transmission infrastructure as a result of the methane emissions mitigation activities. This also includes information on all applicable local, state, and Federal regulations regarding flaring emissions and the facility’s compliance with each. The WEC obligated party must report the time period associated with the emissions that occurred as a result of the delay within the filing year. The WEC obligated party must also affirm that neither the production segment entity impacted by the delay nor the gathering or transmission infrastructure entity seeking the permit contributed to the unreasonable delay.

The EPA requires this information for the verification of exemption eligibility and of exempted emission quantity. Reported information will be used to conduct verification as discussed in section III.A.4., and reported information, records and other information as applicable will be used to conduct any auditing that occurs under section III.E.1.

The EPA seeks comment on the reporting and recordkeeping requirements for the exemption for unreasonable delay in environmental permitting. We seek comment on whether additional information should be collected or retained to allow for verification of the quantity of emissions eligible for the exemption.

2. Regulatory Compliance Exemption Under CAA Section 136(f)(6)

CAA section 136(f)(6) establishes a regulatory compliance exemption for subpart W facilities that are “subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111” upon an Administrator determination that the criteria at CAA section 136(f)(6)(A) have been met. In this action, the EPA is proposing: when the Administrator determinations will be made; the time at which the regulatory compliance exemption would become available to eligible facilities; the process for how the Administrator determinations will be made; how to interpret CAA section 136(f)(6)(A) to govern the interaction between WEC applicable facilities and CAA section 111(b) affected facilities and CAA section 111(d) designated facilities (collectively referred to in this preamble as “CAA section 111(b) and (d) facilities”) for the purposes of the regulatory compliance exemption; how “compliance” with the methane emissions requirements promulgated under CAA sections 111(b) and (d) will be defined for the purposes of the regulatory compliance exemption; reporting requirements for the regulatory compliance exemption; and the process for resumption of the

WEC pursuant to CAA section 136(f)(6)(B) if the criteria for the regulatory compliance exemption are no longer met.

The EPA believes the Congressional intent of this exemption was twofold: 1) to be implemented such that the WEC acts as a bridge to full implementation of the Final NSPS OOOOb and EG OOOOc by encouraging methane reductions in the near term while state plans are being developed, and thereafter exempting from the charge facilities that are in compliance with the requirements pursuant to the final NSPS OOOOb and EG-OOOOc-implementing state and Federal plans,[31] and 2) to encourage timely implementation of requirements in the final NSPS OOOOb and EG OOOOc-implementing state and Federal plans in order to ensure that those requirements achieve meaningful emissions reductions. The EPA's proposed approach for implementing the regulatory compliance exemption is based on a plain reading of the statutory text in CAA section 136(f)(6). The EPA strives to create a program that is straightforward to implement and enforce.

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[31] Under the Tribal Authority Rule (TAR), eligible Tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a Tribal implementation plan (TIP) implementing the EG codified in 40 CFR part 60, subpart OOOOc. The TAR authorizes Tribes to develop and implement their own air quality programs, or portions thereof, under the CAA. However, it does not require Tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. If a Tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities. In this proposal, all uses of the phrase "state and Federal plans" are intended to include any Tribal plans, to the extent that any Tribal plans are developed to implement EG OOOOc.

The EPA interprets the intent of the WEC to be to incentivize reduction of methane emissions across the oil and gas industry. For industry segments not covered by NSPS OOOOb/EG OOOOc, the WEC incentivizes, but does not require, early and sustained emissions mitigation activity. For WEC applicable facilities in industry segments that are covered by NSPS OOOOb/EG OOOOc, the WEC incentivizes, but does not require, methane emissions reductions earlier than may otherwise be required pursuant to NSPS OOOOb and EG OOOOc-derived state and Federal plans. Once those requirements are in effect, the EPA believes the purpose of the regulatory compliance exemption is to provide relief from the WEC to owners or operators that are fully complying with those requirements, and to broadly encourage compliance. This structure ensures that there is an incentive (or requirement) for methane emission reductions from new and existing sources in place at all times, while also avoiding regulation of the same emissions under both the WEC and the NSPS OOOOb and EG OOOOc-implementing state and Federal plans once the regulatory compliance exemption becomes available.

The EPA expects that, as CAA section 111(b) and (d) facilities implement and comply with the methane emissions requirements of NSPS OOOOb and EG OOOOc-implementing state and Federal plans, many of the WEC applicable facilities that contain those emissions sources subject to NSPS OOOOb and EG OOOOc-derived state and Federal plans would be expected to fall below the waste emissions thresholds, and thus not be subject to the WEC. However, the regulatory compliance exemption recognizes that certain WEC applicable facilities may remain above the waste emissions thresholds even after implementation of the requirements in the final NSPS OOOOb and approved state and Federal plans under EG OOOOc; the regulatory compliance exemption would shield such owners or operators that are in compliance with those requirements from additional regulation under the WEC.

Congress provided that the regulatory compliance exemption would only come into effect after "(i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities" and "(ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by [the NSPS OOOOb/EG OOOOc 2021 Proposal], if such rule had been finalized and implemented." The EPA's understanding of these provisions is that Congress intended to provide an incentive for states to move promptly in adopting their plans, and to encourage those plans to achieve meaningful emissions reductions. These two drivers are manifested in the Administrator determinations that must be made before the regulatory compliance exemption becomes available: the first Administrator determination, per CAA section 136(f)(6)(A)(i), that the final NSPS OOOOb and all EG OOOOc-implementing state and Federal plans are "approved and in effect"; and the second Administrator determination, per section 136(f)(6)(A)(ii), that the emissions reductions achieved by these requirements are equal to or greater than the reductions that would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal, had that rule been finalized and implemented as proposed (the "equivalency determination"). These requirements mean that if the final NSPS OOOOb or EG OOOOc-implementing state or Federal plans are delayed, or the requirements therein are collectively less stringent than those in the NSPS OOOOb/EG OOOOc 2021 Proposal, the exemption would not be available and WEC applicable facilities that exceed the waste emissions threshold would not be eligible for the regulatory compliance exemption from the WEC until the conditions are met.

Here, we summarize the proposed approach for the regulatory compliance exemption. Elements of the proposal, other options considered, and requests for comment are discussed in more detail in the sections below.

The EPA is proposing that the prerequisite Administrator determinations for the regulatory compliance exemption would be made after all state and Federal plans pursuant to CAA section 111(d) are approved and in effect. Separate from the timing of the Administrator determinations, the WEC program must establish when the regulatory compliance exemption becomes available at the facility level (*i.e.*, when eligible facilities can be exempted from the WEC), by defining when WEC applicable facilities that are subject to methane emissions requirements pursuant to NSPS OOOOb and EG OOOOc-implementing state and federal plans are in compliance with those requirements. The EPA believes that the regulatory compliance exemption is intended to provide relief from the WEC when the requirements in the final NSPS OOOOb and EG OOOOc-implementing state and Federal plans are in effect in all states. In this interest, the EPA is proposing that WEC applicable facilities would be eligible for the regulatory compliance exemption as soon as the Administrator determinations have been made, rather than when the applicable requirements in state and Federal plans are fully implemented. Thus, under the EPA's proposed approach, the regulatory compliance exemption would become available to facilities as soon as the Administrator determinations are made under CAA section 136(f)(6)(A)(i) and (ii).

The EPA is also proposing further elements of the process for the Administrator determinations under CAA section 136(f)(6)(A)(i) and (ii), including establishing the relative points of comparison for the equivalency determination, in order to ensure that those elements align with the statutory requirements. Because the Administrator determinations cannot be made until all plans are approved and in effect, and because the timing for both Administrator determinations is aligned, the EPA proposes that two the determinations be made together via a single future administrative action.

The EPA is proposing that a WEC applicable facility's eligibility for the regulatory compliance exemption would be based on the compliance status of all of the CAA section 111(b) and (d) facilities contained within that WEC applicable facility. To be eligible for the exemption, the EPA proposes that all of the regulated emissions sources must be in full compliance with their respective methane emissions requirements under the NSPS and EG-implementing state and Federal plans.

The EPA is also proposing reporting requirements for the regulatory compliance exemption. In order to reduce the burden on industry, the EPA proposes that only WEC applicable facilities that are eligible for the exemption would be required to report all associated data elements. Finally, the EPA is proposing how access to the regulatory compliance exemption would be removed for all WEC applicable facilities if the criteria associated with the Administrator determinations were no longer met. The EPA's proposed approach for removing access to the exemption mirrors the conditions that must be met in order for it to become available.

a. Timing for Regulatory Compliance Determinations

Before the regulatory compliance exemption becomes available to facilities, CAA section 136(f)(6)(A) requires determinations to be made by the Administrator that (1) "methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities" and (2) that "compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the [NSPS OOOOb/EG OOOOc 2021 Proposal], if such rule had been finalized and implemented." The EPA believes that Congress intended these prerequisites to exemption availability to encourage timely implementation of the requirements in the final NSPS and state and Federal plans and to ensure that those requirements achieve meaningful emissions reductions.

The first Administrator determination is related to the timing of final methane emissions standards under CAA section 111(b) and state and Federal plans pursuant to an EG issued under CAA section 111(d). The EPA proposes to interpret the language in CAA section 136(f)(6)(A)(i) to mean that this temporal requirement is only met when *both* (1) emission standards for new sources under CAA section 111(b) are promulgated and in effect and (2) all state plans for existing sources pursuant to an EG issued under CAA section 111(d) have been approved by the EPA and are in effect. As to the latter element, the EPA also proposes to interpret the reference to "plans pursuant to subsection... (d) of section 111" to include the promulgation of a Federal plan where the EPA determines that one or more states have failed to submit an approvable state plan, as that is the only way a plan pursuant to CAA section 111(d) would take effect in those states. The EPA further proposes to interpret “all states” in CAA section 136(f)(6)(A)(i) to mean that every state with an applicable facility (*i.e.*, all states with subpart W facilities containing CAA section 111(b) or (d) facilities) must have an approved plan (state or Federal) before the determination can be made. Accordingly, because the emissions standards for new sources under CAA section 111(b) will be finalized before the submittal of state plans for existing sources under CAA section 111(d), approval of the final state (or Federal) plan for states with designated facilities would determine the timing for when the determination could be made under the proposed approach. The EPA proposes that this determination would be made after all CAA section 111(d) plans (*i.e.*, state or Federal plans) have been approved and are in effect. The EPA believes that the proposed approach and interpretation of “all states” is aligned with a plain reading of the statutory text. In particular, the EPA notes the relationship between the use of the singular in section 136(f)(6)(A), directing the EPA to make “a determination”, and the requirements outlined in 136(f)(6)(A)(ii) and (ii), providing that this determination is dependent on EPA finding that (1) standards and plans “have been approved and are in effect in all states” and that (2) compliance with the standards and plans “will result in equivalent or greater emissions reductions as would be achieved by the [2021] proposed rule…”[32] The text strongly indicates that the EPA must make *one* determination after all standards and plans are in place in all states in order to make the exemption available, and further that the determination cannot be

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[32] 42 U.S.C. 7436(f)(6)(A).

made until standards and plans are in place in all states because the equivalency determination must be made on a nationwide scale.[33]

The EPA considered an alternative approach for the determination that methane emissions standards and plans have been approved and are in effect in all states. This alternative would involve a determination for methane emissions standards after the promulgation of final emissions standards for CAA section 111(b) facilities and then determinations on a state-by-state basis as each state plan containing emissions standards for CAA section 111(d) facilities were submitted and approved by the EPA (or a Federal plan was promulgated where a state did not submit an approvable plan). The EPA believes that this state-by-state approach is inconsistent with a plain reading of CAA section 136(f)(6)(A)(i), which mandates that emissions standards and plans must be approved and in effect in *all* states with respect to the applicable facilities (*i.e.*, all states with subpart W facilities containing CAA section 111(b) or (d) facilities). The EPA requests comment on the proposed approach and an alternative approach that would make determinations on a state-by-state basis as each state plan was approved.

The second determination that must be made before the regulatory compliance exemption becomes available is whether the final “methane emissions standards and plans” provide equivalent or greater emissions reductions than would have been achieved by the NSPS

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[33] Note that while the EPA believes that the statute instructs us to make a determination after the plans are collectively in place (rather than making multiple state-by-state determinations), that does not preclude the EPA from reviewing and revising the determination if a standard or plan is later revised, to ensure that the conditions of section 136(f)(6)(A) are still met, consistent with the resumption of charge language in section 136(f)(6)(B).

OOOOb/EG OOOOc 2021 Proposal, had that proposal been finalized and implemented as proposed. Based on a plain reading of the statutory text, because plans pursuant to CAA section 111(d) will not be finalized for several years, the EPA cannot propose an equivalency determination in this action. Instead, we propose that the equivalency determination will be made via an administrative action after all CAA section 111(d) plans (*i.e.*, state or Federal plans) have been approved. This proposed timing would allow evaluation of the emissions reductions achieved by the final NSPS and by all final state and Federal plans.

The EPA also assessed making the equivalency determination for CAA section 111(b) affected facilities before making it for CAA section 111(d) designated facilities. In this proposal, the EPA interprets CAA section 136(f)(6)(ii) as requiring a comparison of the emissions reductions that will be achieved by the final NSPS OOOOb/EG OOOOc and the reductions that would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal if finalized as proposed. Separate equivalency determinations for CAA section 111(b) facilities and CAA section 111(d) facilities would not provide for a comparison of the total emissions reductions achieved by both rules, and therefore the EPA believes that an approach with separate equivalency determinations would be inconsistent with a plain reading of the statutory text. Further, because both determinations must occur before the exemption becomes available, and because under the proposed approach the determination required by CAA section 136(f)(6)(i) would occur after all plans are approved and in effect, there would be no practical reason for making the equivalency determination for CAA section 111(b) facilities before making it for CAA section 111(d) facilities. Finally, the only purpose for making the equivalency determination for CAA section 111(b) facilities before CAA section 111(d) facilities would be in support of an approach that would make the regulatory compliance exemption available to CAA section 111(b) facilities before CAA section 111(d) facilities. As discussed below in section II.D.2.b of this preamble, such an approach would not align with other elements of this proposal, would not be aligned with the statutory text, and would not be technically feasible. The EPA requests comment on this alternative approach.

b. Timing of Regulatory Compliance Exemption Availability

Separate from the timing of the Administrator determinations, the WEC program must also establish when the regulatory compliance exemption will become available for facilities. Different states will have different start dates and in some cases, phased-in requirements, in state or federal plans under 111(d), resulting in some facilities being in compliance with the methane emissions requirements pursuant to CAA section 111(b) and (d) before others. The EPA believes the inclusion of the regulatory compliance exemption at CAA section 136(f)(6)allows for relief from the WEC when the requirements in the final NSPS and state and Federal plans are in effect. The EPA therefore proposes that the regulatory compliance exemption would become available to all applicable facilities meeting the criteria when the Administrator determinations required by CAA section 136(f)(6)(A)(i) and (ii) have both been made. Both determinations are required before the exemption becomes available, and the determination under CAA section 136(f)(6)(A)(i) would indicate that the requirements promulgated under CAA sections 111(b) and (d) have been approved and are in effect. Because the availability of the exemption is linked to the CAA section 136(f)(6)(A)(i) and (ii) determinations, which the EPA is proposing could only be made after all states with an applicable facility have an approved state or Federal plan in effect, the EPA is proposing that the exemption would become available to all eligible WEC applicable facilities in all states at the same time. Moreover, because methane emissions standards for CAA section 111(b) facilities would be expected to come into effect earlier than those required for CAA section 111(d) facilities in state or Federal plans, the timing for exemption availability would be largely driven by the approval and effective date for the final state or Federal plan (i.e., the last state with CAA section 111(d) facilities to have a plan approved and in effect).

The EPA believes the proposed approach is consistent with the statutory text. CAA section 136(f)(6)(A) states that charges shall not be imposed on an applicable facility “that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111.” In order to receive the exemption, all CAA section 111(b) and (d) facilities contained within a WEC applicable facility would need to demonstrate compliance, as discussed in section II.D.2.f. of this preamble.

This proposal makes the exemption available upon adoption of all plans pursuant to CAA section 111(d) and the issuance of the Administrator’s findings under CAA section 136(f)(6)(A). The EPA proposes that the exemption be available as soon as all state or federal plans are in effect, because facilities can be in compliance with the requirements in plan even if full implementation of those requirements is not required until a future date. Provided that facilities subject to the WEC are in compliance with OOOOb requirements and the requirements in EG OOOOc-implementing plans, the proposed approach also allows such facilities to benefit from the regulatory compliance exemption much earlier than the alternative, described below, of making the regulatory compliance exemption available only once applicable compliance deadlines have passed.

The EPA notes that implementation of the requirements included in state or Federal plans may not be mandated immediately upon the date at which the plan goes into effect. In other words, the plans may include compliance schedules with compliance dates that occur at a future date after plan approval, and such requirements could be implemented over multiple compliance dates in a phased manner or include deadlines for various increments of progress. It is therefore possible for CAA section 111(d) facilities to be in compliance with the methane emissions requirements in a plan even if not all compliance dates included in the plan have come to pass. For example, if an approved state plan were to require a specific type of designated facilities to install emissions controls within a year of the effective date of the state plan, those facilities would be considered in compliance with those requirements for that first year. By providing the exemption as soon as the Administrator’s determinations are made after state or Federal plans are approved and in effect rather than when the requirements in those plans must be implemented, the proposed approach would provide relief from the WEC once CAA section 111(d) facilities are effectively subject to federally enforceable methane emissions requirements pursuant to CAA section 111. The EPA requests comment on the proposed approach of making the regulatory compliance exemption available to all WEC applicable facilities at the time when the two determinations required by CAA section 136(f)(6)(A) have been made.

The EPA considered alternative approaches in developing this proposal for implementing the regulatory compliance exemption but found they would not be consistent with the statutory text, would be more challenging to implement, would unfairly advantage specific facilities and companies, or would not be technically feasible.

First, the EPA considered an approach that would make the exemption available to WEC applicable facilities meeting the criteria at a state-by-state level as the plan pursuant to CAA section 111(d) for each state was approved and became effective. For WEC applicable facilities that span multiple states, the exemption would be available when plans for all states in which the facility is located were approved and in effect. This alternative approach would likely make the exemption available earlier for certain WEC applicable facilities compared to the proposed approach, which would not make the exemption available until plans are approved and in effect in all states. The EPA believes that making the regulatory compliance available at a state-by-state level is inconsistent with the statutory text. As discussed in section II.D.2.a. of this preamble, the EPA’s interpretation of CAA section 136(f)(6)(A) in this proposal is that neither of the determinations that are prerequisites to the regulatory compliance exemption’s availability could be made until plans for CAA section 111(d) facilities have been approved and are in effect for all states. Based on this interpretation, it would not be possible for the exemption to become available on a state-by-state basis as state plans were approved and became effective because the prerequisite determinations could not occur until all state plans were approved and in effect. The EPA also believes the proposed approach will simplify implementation and administration of the regulatory compliance exemption compared to an approach in which the exemption would become available to states at different times. Further, a state-by-state application of the exemption could unfairly advantage and disadvantage WEC applicability facilities or companies based on their geographic location. WEC obligations for operations in states that take longer to develop state plans could be higher than those in states that are able to develop and have plans approved earlier, and thus have access to the exemption. Conversely, the proposed approach of making the exemption available to all states at the same time would be equitable and provide the industry with better regulatory certainty. The EPA requests comment on making the regulatory compliance exemption available on a state-by-state basis based on the finalization of plans for individual states.

Second, the EPA considered an approach that would make the regulatory compliance exemption available to WEC applicable facilities meeting the criteria when the methane requirements for all CAA section 111(b) and (d) facilities have been fully implemented. Under this alternative approach, WEC applicable facilities would only become eligible for the regularly compliance exemption once the compliance dates for the NSPS and the state and Federal plans have passed. Because the compliance deadlines under the final EG OOOOc may occur at some point *after* the timeline for state plan approval and issuance of a Federal plan, this alternative approach would make the regulatory compliance exemption available later than under the proposed approach. This would require the EPA to interpret the phrase “subject to and in compliance with methane emissions requirements” in CAA section 136(f)(A) to mean that the exemption from the charge is available only after all of the requirements for CAA section 111(d) facilities have been fully implemented. In other words, the EPA would read “in compliance with methane emissions requirements” to mean that *all* compliance dates in the NSPS and the state and Federal plans have passed. That might serve to give independent effect to both elements of the statutory phrase “subject to and in compliance with”, but the EPA believes that this alternative approach is not as well aligned with the statutory directive. This is because compliance with the standards may occur at different points in time, both across the NSPS and the state and Federal plans, and even within standards that have phased compliance requirements. This interpretation may have the result of delaying availability of the regulatory compliance exemption for many years, even as facilities are otherwise complying with all *applicable* methane emissions requirements, thus extending the period for which many oil and gas operations would be subject to concurrent regulation under WEC and CAA section 111. Rather, the EPA proposes to conclude that CAA section 111(b) and (d) facilities can be considered to be in compliance with all applicable methane emissions requirements, even prior to the final compliance deadlines, for purposes of the regulatory compliance exemption. While the EPA is not proposing that the exemption would become available when the requirements of all state and Federal plans are fully implemented rather than when all state and Federal plans have been approved and are in effect, the agency requests comment on whether such an approach would be legally and practically justified.

Third, the EPA considered an approach that would make the regulatory compliance exemption available to WEC applicable facilities meeting the criteria at a state-by-state level as the final compliance deadline in a state or Federal plan for CAA section 111(d) facilities was reached. Under this alternative approach, WEC applicable facilities in a given state would have access to the exemption upon the final compliance date for CAA section 111(d) facilities in that state. Because state and Federal plans may establish different compliance timelines for CAA section 111(d) facilities, this approach could make the exemption available to states at different times. For WEC applicable facilities that span multiple states, the exemption would be available when the final compliance date passed in all states in which the facility is located. As with the alternative approach that would make the exemption available after the final compliance deadline for CAA section 111(d) facilities had passed in all states, the EPA does not believe an approach that provides the exemption at a state-by-state level based on compliance dates is as consistent with the statutory text and purpose of the exemption for the reasons discussed in the prior paragraph. The EPA requests comment on an approach that would make the exemption available at a state-by-state level based on each state’s final compliance deadline for CAA section 111(d) facilities.

The EPA also assessed an approach that would make the regulatory compliance exemption available to CAA section 111(b) facilities before CAA section 111(d) facilities. Because compliance with emission standards for CAA section 111(b) affected facilities generally apply upon the effective date of the final NSPS and would be required before emission standards for CAA section 111(d) designated facilities are fully implemented (once state or Federal plans are finalized and in effect), there would likely be several years between compliance with methane emissions requirements for CAA section 111(b) and (d) facilities. The EPA rejected this approach for this proposal, however, based on a plain reading of the statutory text. First, as discussed in section II.D.2.e. of this preamble, the exemption is applied to an entire WEC applicable facility, not the CAA section 111(b) and (d) facilities within that WEC applicable facility, and therefore individual CAA section 111(b) or (d) facilities within a WEC applicable facility cannot be exempted. Second, CAA section 136(f)(6)(A) states that waste emission charges shall not be imposed "on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) *and* (d) of section 111." The EPA believes that a plain reading of this text indicates that compliance with regulations pursuant to both CAA section 111(b) and (d) must be achieved before the exemption becomes available, and that the statute therefore does not, by its terms, permit application of the exemption to CAA section 111(b) facilities before it becomes available to CAA section 111(d) facilities. As discussed in section II.D.2.a. of this preamble, the EPA proposes to make the determinations required by CAA section 136(f)(6)(A)(i) and (ii) after all state or Federal plans have been approved and are in effect. Because the determinations that are required for the exemption to become available would not be made separately for CAA section 111(b) facilities and CAA section 111(d) facilities, the exemption would not be available to CAA section 111(b) facilities before CAA section 111(d) facilities under the proposed approach.

Further, even assuming that this statutory text allowed for some ambiguity, there are practical limitations to implementing the regulatory exemption in a phased manner for CAA section 111(b) and (d) facilities. The WEC calculations are based on methane emissions and natural gas or oil throughput data for subpart W facilities that may contain both CAA section 111(b) and (d) facilities. Because reporting under subpart W does not distinguish between CAA section 111(b) and (d) facilities, there is currently no practical means of implementing a phased implementation of the regulatory compliance exemption. Revising the subpart W reporting requirements to make such distinctions would significantly increase the reporting complexity and burden for the oil and gas industry and would not be possible for certain emissions sources due to different definitions of individual emissions source types in subpart W and at CAA section 111(b) and (d) facilities. Further, while it may be feasible to distinguish emissions from new and existing sources for certain emission source categories, there is no means to distinguish natural gas throughput from CAA section 111(b) and (d) facilities at subpart W facilities that contain both CAA section 111(b) and (d) facilities.

c. Emissions Year in Which Exemption Takes Effect

While the data collected under subpart W for the purposes of WEC calculation are reported on a calendar-year basis (*i.e.*, a reporting year is a calendar year), the date at which all of the criteria for the regulatory compliance exemption will be met is not yet known and could fall at any point in the course of a reporting year. The EPA is proposing that the regulatory exemption will take effect in the reporting year in which the required conditions are met. For example, if all exemption requirements are met in June 2027, all eligible facilities meeting the proposed compliance requirements discussed in section II.D.2.f. of this preamble would be exempt from the WEC for the entire 2027 reporting year. The proposed approach is aligned with the EPA’s interpretation that the regulatory compliance exemption is intended to prevent WEC applicable facilities from being subject to the WEC when their constituent CAA section 111(b) and (d) facilities are in compliance with their applicable standards. The EPA requests comment on the proposed approach, as well as an approach in which the regulatory compliance exemption became effective for eligible facilities in the next calendar year after which all required conditions are met (*e.g.*, if requirements are met in October 2027, the exemption would come into effect for the 2028 reporting year). The EPA also requests comment on an approach that would apply the regulatory exemption for a portion of the reporting year based on when all exemption requirements were met, and how reported emissions and throughput data could be quantified, such as through prorating.

d. Approach for Regulatory Compliance Determinations

In this action, the EPA is proposing certain elements related to the approach for the CAA section 136(f)(6)(A) Administrator determinations that must occur before the regulatory compliance exemption becomes available. The EPA is proposing that both determinations would be made simultaneously via a future administrative action. For the equivalency determination, the EPA is proposing the geographic scale at which the equivalency determination would be conducted and the specific elements that would be compared. The EPA proposes to address all other elements (e.g., cumulative versus year-by-year) of the equivalency determination in a future administrative action when the analysis is conducted.

The EPA proposes that when the criteria for both determinations are met, the determinations would be made through a single administrative action. As discussed in section II.D.2.a. of this preamble, under the proposed approach neither determination could be made until all state and Federal plans pursuant to CAA section 111(d) have been approved and are in effect. Because the timing for both determinations would be aligned, the EPA believes that making both determinations via a single administrative action will facilitate timely access to the regulatory compliance exemption after the CAA section 136(f)(6)(A)(i) and (ii) requirements have been met. The EPA requests comment on the proposed approach for making both determinations via a single future administrative action, as well as on alternative approaches for making the determinations.

Section 136(f)(6)(A)(ii) of the CAA requires an Administrator determination that compliance with the requirements in the final CAA section 111(b) and (d) rules “will result in equivalent or greater emissions reductions as would be achieved by the [NSPS OOOOb/EG OOOOc 2021 Proposal], if such rule had been finalized and implemented.” The EPA is proposing to conduct the analysis for the purposes of this equivalency determination at a national level, comparing the national-level emissions reductions that would have been achieved under the NSPS OOOOb/EG OOOOc 2021 Proposal (if finalized as proposed) against those that will be achieved upon implementation of the final NSPS OOOOb/EG OOOOc.

The EPA believes that a national evaluation is the most appropriate geographic scale for the purposes of the equivalency determination. The primary concern for the emissions reductions achieved by the NSPS OOOOb/EG OOOOc in the context of the WEC regulatory compliance exemption are methane emissions. Because the climate impacts of these emissions are dependent on their aggregate quantity rather than where they occur, a national-level evaluation will provide an appropriate comparison of the overall impact of the reductions that would have been achieved under the NSPS OOOOb/EG OOOOc 2021 Proposal and those that will be achieved upon implementation of the final NSPS OOOOb and state and Federal plans implementing OOOOc. The EPA also considers a national evaluation to be consistent with the statutory text in CAA section 136(f)(6)(A)(ii), which requires the Administrator's determination to be based on "compliance with the requirements described in clause (i)," where clause (i) describes the collective "methane emissions standards and plans" required by CAA sections 111(b) and (d).

The EPA assessed alternative approaches that would conduct the equivalency determination at the state-by-state level (*i.e.*, each state would need to demonstrate equivalent or greater emissions reductions) and at both the national and state-by-state levels. However, the EPA is not proposing an approach that would conduct the equivalency at the state-by-state level because the EPA believes that this approach is less consistent with the statutory text and purpose. Determinations for individual states would not indicate if the emissions reductions that will be achieved by the final NSPS and state and Federal plans are equivalent or greater than the reductions that would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal, had that rule been finalized and implemented. In other words, if the EPA were to make determinations for individual states and make the exemption available on a state-by-state basis, that could result in not achieving emission reductions equivalent to the NSPS OOOOb/EG OOOOc 2021 Proposal, thus undermining Congress' intent in drafting this provision to incentivize a minimum level of methane emission reductions via the CAA section 111(b) and (d) regulations. The EPA requests comment on the proposed approach of conducting the equivalency determination at the national scale. The EPA requests comment on conducting the equivalency determination at other geographic scales, such as a state-by-state level, as well as an approach that would require an equivalency determination at both the national and state-by-state levels.

The EPA also considered an alternative approach that would conduct the equivalency analysis at a source-by-source level (at either a national or state-by-state scale). Under this alternative approach, the EPA would compare the reductions achieved by individual sources under the NSPS OOOOb /EG OOOOc 2021 Proposal, had that rule be finalized and implemented, and the final NSPS OOOOb/EG OOOOc. As described above, the climate impacts of methane emissions are based on their aggregate quantity, and it is that quantity, therefore, that is necessary for conducting the equivalency determination. Within the specific context of the equivalency determination, it does not matter if the emissions reductions achieved by an individual source under the final NSPS OOOOb/EG OOOOc achieves fewer reductions than it would have under the NSPS OOOOb /EG OOOOc 2021 Proposal, as long as the total emissions reductions achieved by implementation of the final NSPS OOOOb and EG OOOOc-derived state or federal plans across all sources are equivalent or greater than those that would have been achieved across all sources by the NSPS OOOOb /EG OOOOc 2021 Proposal. The EPA therefore believes that it is not reasonable to conduct the equivalency analysis on a source-by-source level and such an approach is not required by the statutory text. However, the EPA requests comment on using a source-by-source approach for the equivalency determination and requests comment on how such an analysis could be conducted.

Because the NSPS OOOOb/EG OOOOc 2021 Proposal was not itself a final rule at the time Congress enacted this Waste Emissions Charge program, no new source emissions standards or emission guidelines had been finalized for CAA section 111(b) and (d) facilities based on the NSPS OOOOb/EG OOOOc 2021 Proposal, no requirements had been finalized for what constitutes an approvable state plan, and no states had submitted state plans pursuant to such hypothetical finalized requirements. As such, the EPA proposes to use the standards proposed in NSPS OOOOb and the presumptive standards proposed in EG OOOOc as the basis for evaluating emissions reductions that would have been achieved had the NSPS OOOOb/EG OOOOc 2021 Proposal been finalized and implemented. In other words, the EPA understands the inclusion of the NSPS OOOOb/EG OOOOc 2021 Proposal as the baseline for the equivalency demonstration to mean that Congress intended for the EPA to assume, for purposes of this analysis, that the proposed standards were finalized as drafted in the NSPS OOOOb/EG OOOOc 2021 Proposal and implemented nationwide. Further, because Congress directs the EPA to compare the emissions that would have been achieved if the NSPS OOOOb/EG OOOOc 2021 Proposal were finalized and implemented against actual CAA section 111(b) and (d) standards once these are finalized and in effect, the EPA believes that Congress must have meant the EPA to assume that the NSPS OOOOb/EG OOOOc 2021 Proposal was finalized and implemented *as proposed*, which is the only way to use it as a point of comparison. Accordingly, for CAA section 111(b) facilities under the NSPS OOOOb/EG OOOOc 2021 Proposal, the EPA proposes to assess the reductions that would have been achieved had the proposed NSPS OOOOb been finalized and implemented. For CAA section 111(d) facilities under the NSPS OOOOb/EG OOOOc 2021 Proposal, the EPA proposes to assess the reductions that would have been achieved had the proposed emissions guidelines been adopted and implemented by all states as proposed.

The EPA believes the proposed points of comparison between the NSPS OOOOb/EG OOOOc 2021 Proposal and the final NSPS OOOOb and final requirements in state and Federal plans derived from EG OOOOc for the equivalency is aligned with a plain reading of CAA section 136(f)(6)(A), and with Congressional intent. The EPA requests comment on the proposed approach. The EPA recognizes that if the NSPS OOOOb/EG OOOOc 2021 Proposal had been finalized as proposed, the requirements for CAA section 111(d) facilities, and the emissions reductions associated with those requirements, would have been based on approved state or Federal plans. In those plans, it is possible that some states may have set different standards of performance than the presumptive standards proposed in EG OOOOc based on a provision of CAA section 111(d)(1) permitting states to "take into consideration, among other factors, the remaining useful life of a source." (The EPA refers to this provision as the "remaining useful life and other factors" provision, or RULOF.) The EPA regulations at 40 CFR part 60 subpart Ba permit states to consider several factors to, with an adequate demonstration, establish standards less stringent than the degree of emission limitation otherwise required by an EG. In such circumstances, the emissions reductions achieved by those state plans would have been less than if the state plans had adopted and implemented the presumptive standards in the final emissions guidelines, had they been finalized. However, because state plans were never developed pursuant to the NSPS OOOOb/EG OOOOc 2021 Proposal, there is no means of reasonably estimating the requirements that may have been included in those state plans and what emissions reductions they would have achieved. The text also counsels against making RULOF assumptions in this case. Because Congress directs the EPA to compare the emissions that would have been achieved if the NSPS OOOOb/EG OOOOc 2021 Proposal were “finalized and implemented” against actual CAA section 111(b) and (d) standards once these are “approved and in effect,” the EPA believes that Congress meant the Agency to assume that the NSPS OOOOb/EG OOOOc 2021 Proposal was finalized and implemented *as proposed*, because that will allow for comparison with emissions reductions achieved under the final CAA section 111(d) plans, which may differ from the proposal in a variety of ways, including as a result of RULOF analysis. It is also reasonable to infer that Congress wanted to guarantee the level of reductions (i.e., “equivalent or greater”[34] than expected by the NSPS OOOOb/EG OOOOc 2021 Proposal) that would ultimately be achieved by the final NSPS OOOOb and EG OOOOc-derived state and Federal plans by only allowing for the exemption if it is determined that the Final NSPS OOOOb/EG OOOOc would achieve at least the level of reductions that were expected from the proposed rule in place at the time CAA section 136 was written and passed. Thus, the EPA believes the intent of CAA section 136(f)(6)(A) is to use the proposed approach of assessing the reductions that would have been achieved had the proposed emissions guidelines in the NSPS OOOOb/EG OOOOc 2021 Proposal been adopted *and* implemented by all states as proposed. The EPA requests comment on other approaches that could be used to estimate the emissions reductions from CAA section 111(d) facilities had the NSPS OOOOb/EG OOOOc 2021 Proposal been finalized and implemented.

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[34] 42 U.S.C. 7436(f)(A)(ii) (requiring a determination by the Administrator that “compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by [the 2021 proposal]”.)

The EPA also recognizes that in the proposed approach for the equivalency determination, analysis of the reductions from CAA section 111(d) facilities under the NSPS OOOOb/EG OOOOc 2021 Proposal would be based on universal adoption of the presumptive standards in the proposed emissions guidelines, while analysis of the reductions achieved by state and Federal plans developed pursuant to the final EG OOOOc would account for any states' use of the RULOF provision to set less stringent standards. The EPA believes the proposed approach of assessing the reductions achieved by final state and Federal plans is aligned with the statutory text and Congressional intent. CAA section 136(f)(6)(A)(ii) states that the point of comparison for the emissions reductions that would have been achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal are those resulting from "compliance with the requirements described in clause (i)." CAA section 136(f)(6)(A)(i) in turn refers to the "methane emissions standards and *plans* pursuant to subsections (b) and (d) of section 111." The EPA's proposed approach to use the reductions that will be achieved by approved state and Federal plans in the equivalency determination is based on the use of "plans" in CAA section 136(f)(6)(A)(i). Further, CAA section 136(f)(6)(A)(ii) establishes that EPA may not make the equivalency determination unless and until it can establish that "compliance with the requirements described in clause (i) *will result in equivalent or greater emissions reductions* as would be achieved by the [NSPS OOOOb/EG OOOOc 2021 Proposal]."[35] As similarly noted above, it is reasonable to infer from this language that Congress intended to guarantee that a minimum level of emissions

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[35] 42 U.S.C. 7436(f)(6)(A)(ii) (emphasis added).

reduction would be achieved by implementation of the CAA section 111 standards before the exemption became available – and because application of the RULOF provision may result in less stringent standards, Congress could not guarantee this minimum level would be achieved unless the equivalency determination considered the reductions actually achieved by the final NSPS and the standards actually set in state plans, including any standards set pursuant to the RULOF provision.

The EPA considered an approach which would compare the NSPS OOOOb/EG OOOOc 2021 Proposal, as proposed, with the final NSPS OOOOb/EG OOOOc as finalized but before implementation and consideration of RULOF, but ultimately rejected this approach. Although this approach would be relatively simple to apply, not taking into account the actual standards adopted in the state plans cannot lead to a sound conclusion about whether the emission reduction target that the statute sets will actually be met in practice. In other words, this approach could not guarantee that the “result” of implementation of the plans will be equivalent reductions, as the statute requires the EPA to determine. Further, CAA section 136(f)(6)(A)(ii) states that “compliance” with the standards should result in equivalent emissions reductions, but in practice, sources are not required to comply with the EG; instead, sources must comply with standards later established in state or federal plans. For these reasons, the EPA believes that comparing the NSPS OOOOb/EG OOOOc 2021 Proposal with the final NSPS OOOOb/EG OOOOc as finalized, but before implementation, is not as well aligned with the statutory text and intent of Congress. The EPA requests comment on its proposed approach and other approaches that could be used to estimate the emissions reductions that will be achieved by plans pursuant to

CAA section 111(d), including comparing the NSPS OOOOb/EG OOOOc 2021 Proposal with the final NSPS OOOOb/EG OOOOc before implementation and consideration of RULOF.

The EPA reviewed comments on this topic submitted in response to the NSPS OOOOb/EG OOOOc 2022 Supplemental Proposal. Those comments informed the EPA’s proposed approach and alternative approaches. While those comments were considered in the development of this proposal, because they were submitted in response to a separate rulemaking, any duplicative or additional comments on this topic must resubmitted in response to this proposal in order to be considered in the development of the final WEC rule.

e. Application of the Regulatory Compliance Exemption to Subpart W Facilities

CAA section 136(f)(6)(A) states: “[c]harges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111” upon an Administrator determination that “(i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities; and (ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the” NSPS OOOOb/EG OOOOc 2021 Proposal.

The EPA notes that an applicable facility in CAA section 136(d) is an entire site or collection of sites, each of which contains individual emissions sources. In contrast, the terms "affected facility"[36] and "designated facility"[37] are used by the EPA in the NSPS and EG regulations, respectively, to refer to an individual emissions source or a group of emissions sources at a site (*e.g.*, a storage tank battery or a collection of pneumatic controllers) to which a standard applies. A single subpart W facility may contain hundreds or thousands of CAA section 111(b) and (d) facilities. The EPA proposes to interpret and implement the regulatory compliance exemption such that an applicable subpart W facility that contains any CAA section 111(b) or (d) facilities would be eligible for the exemption once all other criteria are met (*i.e.*, the Administrator determinations and proposed compliance elements in 40 CFR 99.40). Table 3 shows the subpart W industry segments applicable to the WEC that may contain CAA section 111(b) or (d) facilities. WEC applicable facilities in the offshore production, LNG storage, LNG import and export, and transmission pipeline industry segments do not contain CAA section 111(b) or (d) facilities under the Crude Oil & Natural Gas source category (or any other source category in 40 CFR part 60) and would not be eligible for the regulatory compliance exemption. The EPA proposes that if any future NSPS/EG rules are finalized such that additional industry segments contain CAA section 111(b) or (d) facilities, the WEC applicable facilities in those segments would be eligible for the regulatory compliance exemption.

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[36] "Affected facility" is defined for purposes of an NSPS at 40 CFR 60.2 to mean "with reference to a stationary source, any apparatus to which a standard is applicable."

[37] "Designated facility" is defined for purposes of an EG at 40 CFR 60.21a to mean "any existing facility. . . which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility."

Table 3. Subpart W Industry Segment and CAA Section 111(b) and (d) Facility Overlap

Subpart W Industry Segment Subject to WEC	**May contain CAA Section 111(b) and/or (d) Facilities?**
Onshore petroleum and natural gas production	Yes
Offshore petroleum and natural gas production	No
Onshore petroleum and natural gas gathering and boosting	Yes
Onshore natural gas processing	Yes
Onshore natural gas transmission compression	Yes
Onshore natural gas transmission pipeline	No
Underground natural gas storage	Yes
LNG import and export equipment	No
LNG storage	No

The EPA assessed other potential interpretations of the regulatory compliance exemption while developing the proposed approach. In particular, the EPA assessed an approach that would instead only exempt the emissions from individual CAA section 111(b) and (d) sources, rather than the emissions of the entire subpart W facility. For example, if certain pneumatic devices are regulated under NSPS OOOOb/EG OOOOc pursuant to CAA sections 111(b) and (d), all reported pneumatic device methane emissions from a subpart W facility would be subtracted from that facility’s reported emissions. Under this approach, only emission sources at subpart W facilities that are not also CAA section 111(b) and (d) facilities (*e.g.*, methane slip from engines) would be considered when determining if a facility was above or below the waste emissions threshold. While this approach would exempt emissions associated with individual CAA section 111(b) and (d) facilities that are in compliance with the standards, as anticipated by the language in CAA section 136(f)(6)(A), the EPA does not believe that this approach would be consistent with the other text in that provision that is clear that the exemption applies to the “applicable facility,” which CAA section 136(d) defines as an entire subpart W facility. Further, we do not believe that it would be practical to implement the regulatory compliance exemption in this manner because the individual emissions source types in subpart W do not always align with the individual CAA section 111(b) and (d) facilities. Exempting methane emissions from individual subpart W source types that have a similar name as a CAA section 111(b) or (d) facility may exclude a broader or narrower scope of equipment or components and associated emissions than those subject to the NSPS OOOOb/EG OOOOc. Methane emissions from CAA section 111(b) or (d) facilities therefore cannot be directly subtracted from reported subpart W data.

We request comment on the proposed approach for applying the regulatory compliance exemption to subpart W facilities and the proposed interpretation of the relevant statutory text. We also request comment on extending the regulatory compliance exemption to facilities in industry segments not currently covered by NSPS OOOOb/EG OOOOc requirements, in the event that such regulations pursuant to CAA 111(b) and (d) are finalized in the future. We recognize that the proposed approach to exempt entire subpart W facilities results in the exemption of methane emissions from sources that are not subject to NSPS OOOOb/EG OOOOc. While we believe the proposed approach is the most consistent with the language in CAA section 136(f)(6), we request comment on alternative interpretations.

f. Determining Eligibility With Respect to CAA Section 136(f)(6)(A)

It is expected that for many WEC applicable facilities, implementing NSPS OOOOb/EG OOOOc requirements would reduce methane emissions to levels below the waste emissions thresholds. The EPA interprets the regulatory compliance exemption as intending to provide relief from the WEC for WEC applicable facilities that remain above the waste emissions threshold even when their constituent CAA section 111(b) and (d) facilities (i.e. emissions sources) are in full compliance with their applicable methane emissions requirements. This structure provides a further incentive for compliance with applicable requirements.

The EPA proposes that the regulatory compliance exemption would only be available to WEC applicable facilities that exceed the waste emissions threshold. CAA section 136(f)(6)(A) states that “charges shall not be imposed pursuant to subsection (c) on an applicable facility” that meets the requirements of the regulatory compliance exemption. Subsection (c) in turn states that a charge shall be collected “on methane emissions that exceed an applicable waste emissions threshold.” Based on a plain reading of the statutory text, the EPA proposes that the exemption would not apply to WEC applicable facilities below the waste emissions threshold. Further, providing the exemption to WEC applicable facilities below the waste emissions threshold would serve no purpose as these facilities would not have positive WEC applicable emissions and therefore would not benefit from the exemption. Excluding facilities below the waste emissions threshold from the exemption would also reduce the reporting burden for those facilities, which would not be required to report information related to CAA section 111(b) and (d) compliance status.

As discussed in this section, CAA section 136(f)(6)(A) does not specify the definition of compliance for the purposes of the exemption, and many different types of compliance deviations or violations can occur. The EPA is therefore proposing what actions constitute compliance with a methane emissions requirement, pursuant to CAA section 136(f)(A), for the purposes of implementing the regulatory compliance exemption. The EPA's proposed approach is intended to provide a clear threshold for establishing compliance status and eligibility for the exemption while minimizing the burden on industry and facilitating ease of implementation. The EPA is also proposing related reporting requirements for WEC applicable facilities that are necessary to implement the regulatory compliance exemption (see section II.D.2.g. of this preamble).

CAA section 136(f)(6)(A) states that the WEC shall not be imposed "on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111." For the purpose of determining WEC facility eligibility for the regulatory compliance exemption, the EPA proposes that the compliance status of CAA section 111(b) and (d) facilities contained within a WEC applicable facility would be assessed based on compliance with the applicable methane emissions requirements for the Oil & Natural Gas Source Category (40 CFR part 60, subparts OOOOa, OOOOb, and OOOOc).

Further, the EPA proposes that should additional NSPS/EG regulations for the oil and natural gas industry source category be finalized in the future, compliance with the methane emissions requirements in those regulations would be assessed for determining eligibility for the regulatory compliance exemption. As discussed in section II.D.2.h. of this preamble, the regulatory compliance exemption could become unavailable if future NSPS/EG revisions result in a situation such that those revisions, upon implementation, result in fewer emissions reductions than achieved by the NSPS OOOOb/EG OOOOc 2021 Proposal, had that proposal been finalized and implemented. Similarly, the exemption could be reinstated upon adoption and implementation of NSPS/EG revisions that restore emissions reduction equivalency with, or improvement upon, the NSPS OOOOb/EG OOOOc 2021 proposal. In such cases where a future NSPS/EG rule only applies to equipment in a segment of the oil and natural gas industry not covered by an existing NSPS/EG rule, the EPA proposes that any WEC applicable facilities with existing access to the regulatory compliance exemption would maintain that access. In other words, the “all states” requirement in CAA section 136(f)(6)(A)(i) would be assessed separately for the additional equipment covered by the new NSPS/EG, and any existing access to the exemption would not be lost while the determination is being made that CAA section 111(d) plans pursuant to the new EG rule were approved and in effect.

The EPA requests comment on its proposed approach for how NSPS OOOOa, NSPS OOOOb, and EG OOOOc should be considered for the purposes of the regulatory compliance exemption. The EPA also requests comment on its proposed approach in light of any potential future NSPS/EG rules for the oil and natural gas industry source category, or any other additional source category that might cover emissions sources at a WEC affected facility, and the role of any such future methane emissions requirements in determining eligibility for the regulatory compliance exemption.

The EPA proposes that any WEC applicable facility that contains CAA section 111(b) or (d) facilities would receive the regulatory compliance exemption if each of the CAA section 111(b) and (d) facilities that constitute the WEC applicable facility has no deviations or violations of the methane emissions requirements promulgated pursuant to the applicable NSPS or EG-implementing state and Federal plans. The EPA is proposing that this compliance requirement would apply for each CAA section 111(b) or (d) facility for each reporting year for the WEC applicable facility. For example, if all CAA section 111(b) or (d) facilities contained in a WEC applicable facility were in compliance with the applicable methane emissions requirements during a particular reporting year, the regulatory exemption would apply for that reporting year. If any CAA section 111(b) or (d) facilities contained in a WEC applicable facility in the respective reporting year were not in compliance with emissions requirements, the regulatory exemption would not apply for that reporting year. The EPA proposes that if a WEC applicable facility were to lose access to the regulatory compliance exemption in a reporting year due to a deviation or violation in that reporting year, it would be able to receive the exemption in any subsequent reporting year if there were no deviations or violations in that applicable reporting year.

The EPA is proposing that a WEC applicable facility would not be eligible for the regulatory compliance exemption if any CAA section 111(b) or (d) facility that is contained within the WEC applicable facility has one or more deviations or one or more violations of any methane emissions requirement under the applicable NSPS or state or Federal plan issued pursuant to the EG. The EPA recognizes that there are many potential elements to compliance with the methane requirements promulgated under CAA sections 111(b) and (d), such as compliance with a quantitative emissions limit and compliance with work practice standards, as well as multiple monitoring, recordkeeping, and reporting requirements. The EPA proposes to find that a deviation or violation from any of the methane requirements promulgated under CAA sections 111(b) and (d) constitutes non-compliance for purposes of the regulatory compliance exemption. The EPA believes that this approach is most consistent with the plain language of CAA section 136(f)(6)(A), which states that charges shall not be imposed on a facility that is "*subject to and in compliance with* methane emissions requirements pursuant to subsections (b) and (d) of section 111".[38] First, Congress made clear that it is not enough for a particular facility to be subject to methane regulations; each facility must also comply with those regulations. And in establishing what it means to comply, Congress did not employ any mitigating language. It is not enough to be "substantively" in compliance, for example, or "in compliance with all major requirements". Facilities must be "in compliance with requirements" pursuant to 111(b) and (d).

The EPA evaluated several alternative criteria for the regulatory compliance exemption eligibility. Another interpretation could be to apply a threshold, such as specific quantitative threshold requirements, for the regulatory compliance exemption. For example, the EPA might specify that a WEC applicable facility would still be deemed to be in compliance for purposes of the regulatory compliance exemption where the number of deviations or violations, or a quantity of excess emissions, fall below a specified threshold, as applied for all the CAA section 111(b)

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[38] 42 U.S.C. 7436(f)(6)(A).

and (d) facilities contained in a WEC applicable facility. However, for the reasons discussed in the following paragraph, the EPA is not proposing this alternative.

Deviations from or violations of any compliance requirements can vary significantly in severity and impact, as well as frequency. For example, a WEC applicable facility could contain many CAA section 111(b) and (d) facilities with numerous deviations that, even collectively, result in a small amount of excess emissions. Another WEC applicable facility could contain a single CAA section 111(b) or (d) facility with a single deviation or violation that resulted in methane emissions significantly exceeding those that would have resulted had the CAA section 111(b) or (d) facility been in compliance with its methane emissions requirements. Violations of the emission standards are not the only violations that may be significant. Violations of monitoring requirements can be very serious, given that failure to do monitoring, or doing it incorrectly, can result in significant emissions not being discovered or corrected. Reporting violations can also be very serious, if they result in government being unaware of significant problems and thus unable to address them. For these and many other reasons, there is often no easy way to determine the seriousness of particular violations without fact specific and resource intensive investigation. Given that deviations from and violations of requirements for emission standards under CAA section 111(b) and of state or Federal plan requirements under CAA section 111(d) can vary in type, severity, and frequency, and given that CAA section 136(f)(A) does not further specify what constitutes compliance for the purpose of the regulatory compliance exemption, the EPA is not proposing a specific quantitative threshold requirement for the regulatory compliance exemption (*e.g.*, number of violations or quantity of excess emissions).

Because under the statute the availability of the regulatory compliance exemption requires two threshold findings, including that all plans are approved and in effect, the exemption would not be available until several years after finalization of the WEC rule. See the discussion in section II.D.2.b of this preamble regarding the proposed approach for timing of the regulatory compliance exemption availability. With the exception of several sources (*e.g.*, combustion emissions for certain industry segments), most methane emission sources in covered industry segments required to report emissions under subpart W would also be subject to the CAA section 111(b) or (d) methane requirements promulgated in the final NSPS OOOOb and the plans issued and approved under EG OOOOc. The EPA expects that, as oil and gas operations implement the requirements of final NSPS OOOOb and the plans issued and approved pursuant to EG OOOOc (and undertake other methane mitigation voluntarily or due to other Federal or state regulations), total reported subpart W facility methane emissions would decline.

For many WEC applicable facilities, if the CAA section 111(b) and (d) facilities contained within a WEC applicable facility are in compliance with methane requirements promulgated under CAA sections 111(b) and (d), the WEC applicable facility would likely be below the waste emissions threshold. The Agency therefore expects that even if CAA section 111(b) or (d) facilities within these WEC applicable facility have compliance deviations, these WEC applicable facilities will likely remain below the waste emissions thresholds. In the alternative, the EPA expects that cases of significant or widespread compliance deviations or violations with the requirements promulgated under CAA section 111(b) or (d) could result in emission levels for a WEC applicable facility that could exceed the waste emissions thresholds. Because many WEC applicable facilities are expected to be below the waste emissions threshold when the regulatory compliance exemption becomes available, the EPA expects that deviations or violations will not have a significant impact for these facilities – they would not be eligible for the exemption not only because they are out of compliance, but also because they are below the waste emissions threshold, and there is no charge to exempt in that case.

The EPA requests comment on the proposed provisions for determining “compliance” for the purposes of the regulatory compliance exemption and the alternative approaches the agency considered. The EPA requests comment on specific criteria (*e.g.*, types of deviations or violations, quantitative thresholds) that could be applied to determine compliance with methane emissions requirements promulgated under CAA sections 111(b) and (d) for the purpose of assessing WEC applicable facility eligibility for the regulatory compliance exemption. The EPA requests comment on whether the criteria should consider whether the deviation or violation resulted in excess emissions, as demonstrated by monitoring and other data. The EPA also requests comment on excluding WEC applicable facilities below the waste emissions threshold from the regulatory compliance exemption.

g. Reporting and Recordkeeping Requirements for the Regulatory Compliance Exemption

We are proposing a reporting requirement at 40 CFR 99.7(b)(2)(iv) that would require that once the Administrator has made a determination that the requirements in CAA section 136(f)(6)(A) have been met, information related to the regulatory compliance exemption must be included in the WEC filing submitted by the WEC obligated party for each WEC applicable facility exceeding the waste emissions threshold that contains any CAA section 111(b) and (d) affected facilities. CAA section 136(f)(6)(A) mandates that the EPA shall not impose a charge upon WEC applicable facilities that qualify for the regulatory compliance exemption. The proposed approach for implementing the regulatory compliance exemption would make facilities that are below the waste emissions threshold ineligible for the exemption. The EPA therefore proposes that WEC obligated parties would not be required to report information related to the compliance status of CAA section 111(b) and (d) facilities contained within WEC applicable facilities for WEC applicable facilities that are below the waste emissions threshold.

The reporting requirements for facilities with the regulatory compliance exemption are proposed at 40 CFR 99.42. We are proposing that the filing would include a representation of the NSPS and state and Federal plan compliance status for each CAA section 111(b) and (d) facility located within a WEC applicable facility during the reporting year. This representation of compliance status would indicate whether the facility was in full compliance for the entirety of the reporting year (*i.e.,* for each CAA section 111(b) and (d) facility, there were no violations or deviations), or whether there were one or more deviations or violations during the reporting year. For facilities that meet all eligibility requirements for the exemption, we are proposing to require reporting of the ICIS-AIR ID (or if unavailable, the facility registry service (FRS) ID and EPA Registry ID from CEDRI) reporting identifiers for each CAA section 111(b) and (d) facility located at the WEC applicable facility. These identifiers are information necessary for the EPA to assess the accuracy of the representation of compliance status through linkages to reports and emissions and compliance data for each CAA section 111(b) and (d) facility located at the WEC applicable facility.

As supporting documentation for the representation of compliance status of WEC applicable facilities that are eligible for the exemption but were not in full compliance for the entirety of the reporting year, we are proposing to require the submittal of one report associated with the CAA section 111(b) and (d) facilities located within the WEC applicable facility that documents a deviation or violation during the reporting year. As supporting documentation for the representation of compliance status of WEC applicable facilities that are eligible for the exemption and that were in full compliance for the entirety of the reporting year, we are proposing to require the submittal of report(s) associated with the CAA section 111(b) and (d) facilities located within the WEC applicable facility. The EPA recognizes that the compliance certification period for CAA section 111(b) and (d) facilities may not align with the reporting year for which the filing is being completed and that at the time of the WEC filing due on March 31 of each year, report(s) covering the complete preceding reporting year for WEC filing may not be available. To accommodate for these cases where a report is not available for the complete reporting year of WEC filing, the EPA is proposing that the WEC obligated party would provide the report, if available, that covers a portion of the year, identify the period of time covered by the report, and for the remainder of the year provide a representation of compliance status for each CAA section 111(b) and (d) facility at the WEC applicable facility that is not included in the submitted report. It also is possible that the complete calendar year of WEC filing is covered by two annual reports, each covering a portion of the calendar year. In this case, the WEC applicable facility should submit both annual reports. The EPA further recognizes that a WEC applicable facility may contain CAA section 111(b) and (d) facilities that first became subject to requirements under CAA sections 111(b) and (d) during the reporting year associated with the filing and for which the first year of compliance is not completed. For these CAA section 111(b) and (d) facilities, we are proposing to require that the filing identify the type of facility, that date that it became subject, and a representation of the compliance status for the portion of the year in which it was subject to requirements under CAA sections 111(b) and (d). In cases where the initial filing does not include a report covering the entire reporting year, we are proposing to require that the WEC obligated party provide a revised filing once such a report becomes available. The EPA is proposing that this revised filing under the WEC rule would be required to be made on or before the date that the compliance report covering the remainder of the year would be due under the applicable requirements of CAA section 111(b) or (d). The deadlines for filing revisions to WEC filings as discussed in section III.A.4. do not apply for the submittal of compliance reports.

The EPA requires this information for the verification of exemption eligibility. Reported information will be used to conduct verification as discussed in section III.A.4., and reported information, records and other information as applicable will be used to conduct any auditing that occurs under section III.E.1.

The EPA is aware that this proposed reporting program may result in cases where a WEC obligated party makes a good-faith representation that each CAA section 111(b) and (d) facility at the WEC applicable facility is in compliance but later independently discovers the existence of one or more deviations or violations. In this proposed rulemaking, such independent discoveries would be considered to be substantive errors within the WEC filing. Proposed 40 CFR 99.7(e)(1) would require submittal of a revised WEC filing within 45 days of the discovery that a previously submitted WEC filing contains a substantive error. Provided that timely submittal of a revised filing is made, if a revised regulatory compliance exemption filing results in the imposition of WEC obligation from a WEC applicable facility that previously qualified for exemption, we are proposing that the WEC obligated party would not be subject to interest penalties normally assessed for payments made after March 31, as discussed in section III.B.1. of this preamble.

However, later discoveries of deviations or violations by the EPA or another regulatory authority, or discoveries as a result of investigation by the EPA or another regulatory authority (including information requests), are not treated the same way as errors. Where a WEC obligated party represents that each CAA section 111(b) and (d) facility at the WEC applicable facility is in compliance, but the EPA or another regulatory authority subsequently discovers the existence of one or more deviations or violations, or the CAA section 111(b) and (d) facility identifies the deviation or violation as a result of an EPA investigation (including information requests), the WEC obligated party may be subject to enforcement and required to pay any outstanding WEC fees and interest penalties. False statements may be subject to criminal enforcement.

The EPA seeks comment on the reporting and recordkeeping requirements for the regulatory compliance exemption. We seek comment on whether additional information should be collected or retained to allow for verification of eligibility for the exemption.

h. Resumption of WEC Under CAA Section 136(f)(6)(B)

CAA section 136(f)(6)(B) states that if, at any point after the Administrator has made the determination required by CAA section 136(f)(6)(A), the conditions for such determination are no longer met, the regulatory compliance exemption ceases to apply. Because the EPA proposes to determine that the regulatory compliance exemption is only available if *all states* are subject to standards and plans pursuant to CAA sections 111(b) and (d) that are, collectively, equivalent to the NSPS OOOOb/EG OOOOc 2021 Proposal, the EPA proposes that all WEC applicable facilities would lose access to the exemption if either of the conditions in CAA section 136(f)(6)(A) ceased to apply. For example, if a state plan were legally challenged and vacated after the initial determination, plans would no longer be approved and in effect in all states, and the regulatory compliance exemption would no longer be available. Similarly, if after the initial equivalency determination methane emissions requirements promulgated under CAA section 111(b) or (d) were modified such that they no longer resulted in equivalent or greater aggregate emissions reductions than the NSPS OOOOb/EG OOOOc 2021 Proposal, the exemption would no longer be available. Note that in addition to future revisions to EG, revisions to the requirements in individual state plans pursuant to CAA section 111(d) could also result in a situation in which implementation of the final NSPS and state or federal plans does not achieve equivalent or greater emissions reductions compared to the 2021 NSPS OOOOb/EG OOOOc Proposal. (The conditions under which an individual WEC applicable facility would receive or become ineligible for the regulatory compliance exemption while the conditions in CAA section 136(f)(6)(A) are still met are discussed in section II.D.2.f. of this preamble.) The EPA proposes that any determination that the criteria in CAA section 136(f)(6)(A) are no longer met after the initial determination would be made through a future administrative action. The EPA proposes that access to the exemption would be lost for the full calendar year in which the required criteria were no longer met. The EPA proposes that if access to the regulatory compliance exemption were lost after it was initially made available because one of the two required conditions in CAA section 136(f)(6)(A) were no longer met, it could become available again following a subsequent determination that both conditions were once again achieved. Under such circumstances, the exemption would become available again for the reporting year in which the conditions were met. The EPA proposes that if the conditions ceased to apply and were then met again in the same reporting year, the exemption would be available for the entire reporting year. The EPA requests comment on alternative approaches that would revoke the regulatory compliance exemption for a portion of the year in which the requirements were no longer met and how data under such an approach could be pro-rated for the purposes of determining WEC. The EPA requests comment on the proposed implementation of CAA section 136(f)(6)(B). While the EPA believes the proposed implementation of CAA section 136(f)(6)(B) is consistent with a plain reading of the statutory text and consistent with the proposed timing of the regulatory compliance determinations under CAA section 136(f)(6)(A) (*i.e.*, methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in *all States*), the agency requests comment on an approach in which access to the exemption would be lost at a state-by-state level. In this alternative approach, if circumstances occurred such that a state plan was no longer approved and in effect, only the WEC applicable facilities located in that state would lose access to the exemption; for WEC applicable facilities that span multiple states, access would be lost if the state plan for any of the states in which the WEC applicable facility is located were no longer approved and in effect.

3. Plugged Well Exemption Under CAA Section 136(f)(7)

Plugged wells have lower methane emissions than active wells and unplugged inactive wells; therefore, plugging wells will reduce total facility emissions potentially subject to WEC. Congress created an incentive for plugging and permanently shutting wells by including an exemption from the WEC in CAA section 136(f)(7): "[c]harges shall not be imposed with respect to the emissions rate from any well that has been permanently shut-in and plugged in the previous year in accordance with all applicable closure requirements, as determined by the Administrator.". Separately, in CAA section 136(a)(3)(D) and 136(b), Congress provided funding that can assist owners and operators who elect to voluntarily and permanently shut in and plug wells on non-Federal land.[39]

In this rule, we are proposing that this exemption would be applicable to wells in the onshore and offshore petroleum and natural gas production industry segments. We interpret this exemption to apply to the production industry segments only and not to wells in other segments,

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[39] On August 30, 2023, the EPA, U.S. Department of Energy, and National Energy Technology Laboratory announced the availability of up to $350 million in formula grant funding to eligible states to help monitor and reduce methane emissions from marginal conventional wells, including to help owners and operators voluntarily and permanently reduce methane emissions from marginal conventional wells. Inflation Reduction Act (IRA) – Mitigating Emissions from Marginal Conventional Wells, Funding Opportunity Number DE-FOA-003109, available at: *https://www.grants.gov/web/grants/view-opportunity.html?oppId=350045*.

such as storage wells. Production wells are distinctly different in purpose and emissions profile than underground storage wells, which are generally replaced with new storage wells then they are plugged and abandoned. We seek comment on including wells in the underground natural gas storage industry segment under this exemption. We are proposing that in the WEC filing, exempted emissions would be those from wells permanently shut-in and plugged in the previous year (*i.e.*, if a well is permanently shut-in and plugged in 2026, the exempted emissions would be deducted from the 2026 emissions totals that are filed under WEC in 2027).

a. Determining if the Exemption for Permanently Shut-In and Plugged Wells Applies to a WEC Applicable Facility

The EPA is proposing two criteria for determining if the exemption for permanently shut-in and plugged wells applies to a WEC applicable facility.

Consistent with the other exemptions, the first criterion is that the facility must have emissions that exceed the waste emissions threshold. CAA 136(c)(7) notes that “charges shall not be imposed” on emissions from permanently shut-in and plugged wells. Charges would not be imposed on emissions below the threshold and therefore an exemption is unnecessary in cases where facility emissions are below the threshold. The EPA proposes that emissions from facilities that are below the waste emissions threshold would not be exempted. The EPA proposes that for facilities that exceed the waste emissions threshold, emissions eligible for the plugged well exemption could be subtracted up to the point where facility emissions equal the waste emissions threshold (*i.e.*, the lowest possible WEC applicable emissions for a facility with the plugged well exemption would be zero).

Second, wells must meet the following definition of permanently shut-in and plugged in accordance with all applicable closure requirements. The EPA proposes that for the purposes of this exemption, a permanently shut-in and plugged well is one that has been permanently sealed to prevent any potential future leakage of oil, gas, or formation water into shallow sources of potable water, onto the surface, or into the atmosphere. For the purposes of this exemption, the EPA is proposing that a well would be considered to be permanently shut-in and plugged, in accordance with all applicable closure requirements, if the owner or operator has met all applicable Federal, state, and local requirements for closure in the jurisdiction where the well is located. For the purposes of this exemption, we are proposing that a well would be considered permanently shut-in and plugged on the date a metal plate or cap has been welded or cemented onto the casing end.

Section II.D.3.c. below details the reporting requirements for this exemption which provide information necessary for verification of the exemption eligibility and exempted emission quantities.

In addition to requirements specifying how to plug a well, relevant Federal, state, and local requirements often also specify requirements such as for notifications, reporting, and site remediation. For purposes of 40 CFR part 99, we propose that the applicable closure requirements would include only the requirements specific to well plugging. We are not proposing to include requirements for notifications, reporting, and site remediation as part of the exemption eligibility criteria for following “all applicable closure requirements” because the closure of the well is the key activity impacting methane emissions, which is the focus of the

WEC, and these other aspects of closure are less relevant to methane emissions levels. We also note that had we proposed to include these additional requirements in our interpretation of "all applicable closure requirements," the reporting requirements would increase for permanently shut-in and plugged wells and this may lead to recalculations of WEC years after the exemption was initially applied. We request comment on whether "all applicable closure requirements" should instead be interpreted to include notifications, reporting, site remediation and other post-closure activities at plugged well.

b. Calculations of Exempted Emissions from Permanently Shut-In and Plugged Wells

The EPA proposes that the methane emissions eligible for the exemption are those that occur at the well level including those from wellhead equipment leaks, liquids unloading, and workovers with and without hydraulic fracturing in the reporting year in which the well was plugged. We are proposing to only consider these emissions sources in the calculation of exempted emissions for the permanently shut-in and plugged well as we expect use of production-related equipment or equipment associated with treating production streams generally (*e.g.,* AGRU, dehydrator, separator) to be at a minimum. We are proposing to limit the emissions quantity to the source types we expect to represent the most significant emissions share expected at permanently shut-in and plugged wells. We note that methane emissions in the reporting year from other equipment onsite (*e.g.*, separator, compressor, flare) may result from multiple wells and not just the wells that are plugged in the reporting year. We request comment on an interpretation that would exempt all methane emissions associated with the production from the permanently shut-in and plugged well – not limited to the wellhead equipment leaks, liquids unloading, and workovers as is included in this proposal – during the calendar year of closure, including the methodology by which methane emissions from non-wellhead specific sources in subpart W could be attributed to the permanently shut-in and plugged well.

For the purposes of quantifying the methane emissions from equipment leaks, liquids unloading, workovers with hydraulic fracturing, and workovers without hydraulic fracturing associated with each permanently shut-in and plugged well, we are proposing to use the methane emissions and throughput data collected or reported to subpart W of part 98. As discussed previously in this preamble, proposed amendments in the 2023 Subpart W Proposal impact the data available to best estimate the exempted emissions from the permanently shut-in and plugged well. Therefore, as described in more detail in this section, for applicable emission sources and industry segments, different approaches are proposed for certain time periods.

The current subpart W rule requires that onshore petroleum and natural gas production facilities report methane emissions from liquids unloading and workovers to be reported by sub-basin for each WEC applicable facility as well as methane emissions from equipment leaks at the facility-level. Subpart W of part 98 also currently requires offshore petroleum and natural gas production facilities and onshore petroleum and natural gas production facilities to report facility-level throughput of gas and oil handled or sent to sale, respectively. Proposed revisions included in the 2023 Subpart W Proposal would require onshore petroleum and natural gas production facilities to report additional elements that facilitate quantification of methane emissions from individual shut-in and plugged wells. Specifically, beginning in reporting year 2024, the 2023 Subpart W Proposal would require onshore petroleum and natural gas production facilities to report well-level throughput volumes for gas and oil sent to sale from wells that are permanently shut-in and plugged. Additionally, beginning in reporting year 2025, the 2023 Subpart W Proposal would increase the granularity of methane emissions reporting for liquids unloading and workovers to the well-level and methane emissions reporting for equipment leaks to the well pad level. Due to the differences in available reporting data for 2024 and future years, the proposed approach for quantifying methane emissions in part 99 for individual wells located at onshore petroleum and natural gas production facilities that are permanently shut-in and plugged in 2024 would be different than the proposed approach for quantifying methane emissions from wells located at onshore petroleum and natural gas production facilities that are permanently shut-in and plugged in 2025 and future years.

For reporting year 2024, the EPA proposes through 40 CFR 99.52 that WEC applicable facilities in the onshore petroleum and natural gas industry segment would quantify methane emissions from permanently shut-in and plugged wells by allocating the subpart W of part 98 reported facility-level equipment leak, liquids unloading, and workover methane emissions using subpart W of part 98 reported production volumes of gas and oil sent to sale. We are proposing that WEC applicable facilities in the onshore petroleum and natural gas industry segment would sum the total subpart W of part 98 reported methane emissions from equipment leaks, liquids unloading, and workovers, and multiply the sum of the methane emissions by the ratio of subpart W of part 98 reported production at the permanently shut-in and plugged well to the subpart W of part 98 reported facility-level total production.

For facilities with only gas production with exempt plugged well emissions, we are proposing that the reported gas produced from the plugged wells be divided by the total gas production at the facility to develop the ratio. For facilities with only oil production with exempt plugged well emissions, we are proposing that the reported oil produced from the plugged wells be divided by the total oil production at the facility to develop the ratio. For facilities with both gas and oil production with exempt plugged well emissions, we are proposing that gas production that is reported to subpart W of part 98 by the WEC applicable facility in the onshore petroleum and natural gas industry segment would be converted to barrels of oil equivalent using a default value of 6,000 scf/barrel, such that throughput volumes will be on the same basis for facilities that report production of gas and oil. We are seeking comment on whether the EPA should provide an option for WEC applicable facilities to use a facility-specific value for barrels of oil equivalent, including whether facilities routinely determine this value and whether significant variability is expected in this value.

For 2025 and future years, we are proposing that WEC applicable facilities in the onshore petroleum and natural gas industry segment would estimate well-level emissions in accordance with part 98 methods for the permanently shut-in and plugged well. As described previously, for 2025 and future years, subpart W of part 98 would require reporting of methane emissions from liquids unloading and workovers to be at the well-level for facilities in the onshore petroleum and natural gas industry segment, therefore we are proposing that facilities in the onshore petroleum and natural gas industry segment would utilize the methane emissions as -reported to subpart W part 98 in their part 99 exemption calculation for these emissions sources. Also, as described previously, for 2025 and future years, subpart W of part 98 would require reporting of methane emissions from equipment leaks at the well pad for facilities in the onshore petroleum and natural gas industry segment. In order to obtain a well-level estimate for the part 99 exemption calculation, we are proposing to require facilities in the onshore petroleum and natural gas industry segment to utilize the subpart W of part 98 input data and emission estimation methods for wellhead equipment leaks to calculate the methane emissions at the well level for the permanently shut-in and plugged well. For example, if the equipment leak methane emissions at the well pad that includes the permanently shut-in and plugged well were estimated using the leaker method in 40 CFR 98.233(q), the WEC applicable facility would use the count of leakers by component type (*e.g.*, valve, connector) recorded for the permanently shut-in and plugged well, the operating time of the well during the year, and the appropriate emissions factors from subpart W of part 98 to estimate the methane emissions from the permanently shut-in and plugged well. Similarly, if the equipment leak methane emissions at the well pad that includes the permanently shut-in and plugged well were estimated using the population count method in 40 CFR 98.233(q), the WEC applicable facility would use the operating time of the well during the year and the appropriate emissions factors from subpart W of part 98 to estimate the emissions from the permanently shut-in and plugged well.

For offshore petroleum and natural gas production facilities, the current subpart W of part 98 reporting requirements are based on the facility’s submission to the Bureau of Ocean Energy Management (BOEM), which includes methane emissions for component-level equipment leaks. The methane emissions required to be reported by offshore facilities would be unchanged by the

2023 Subpart W Proposal as it pertains to this exemption in that these facilities will continue to report the data from their BOEM report. Subpart W of part 98 also currently requires offshore petroleum and natural gas production facilities to report facility-level throughput of gas and oil handled in the reporting year. Proposed revisions included in the 2023 Subpart W Proposal for offshore petroleum and natural gas production facilities would add requirements for the reporting of well-level throughput volumes for gas and oil sent to sale from wells that are permanently shut-in and plugged beginning in reporting year 2024. The 2023 Subpart W Proposal would also revise the terms in the current reporting elements for facility-level throughputs to refer to gas sent to sale, rather than handled, for consistency with the CAA language and with the onshore production industry segment. As noted in the preamble for the 2023 Subpart W Proposal, these verbiage changes for facility-level throughput are not expected to impact the quantity of production volumes reported and were made for consistency and clarity. For the purposes of estimating the exempted emissions for permanently shut-in and plugged wells at offshore petroleum and natural gas production facilities, we are proposing that facilities allocate the component level equipment leaks (*i.e.*, those from valves, connectors) reported to subpart W of part 98 by the ratio of production from the well that has been permanently shut-in and plugged to the total facility-level production. Analogous to the approach for onshore petroleum and natural gas production facilities for reporting year 2024, we are proposing that gas sent to sale be converted to BOE using a default value of 6,000 scf/bbl BOE.

For all reporting years and applicable industry segments, if the WEC applicable facility has more than one permanently shut-in and plugged well, we are proposing that the part 99 emissions calculations would be performed for each well and summed to determine the net annual quantity of methane emissions at the WEC applicable facility eligible for the exemption.

c. Reporting and Recordkeeping Requirements for the Exemption for Permanently Shut-In and Plugged Wells

Through the provisions proposed at 40 CFR 99.51, the EPA is proposing that the WEC obligated party receiving the exemption would provide for each well at a WEC applicable facility, the well ID number as reported to subpart W of part 98; the date the well was permanently shut-in and plugged; the statutory citation for each state, local, and Federal regulation stipulating requirements that were applicable to the closure of the permanently shut-in and plugged well; the emission attributable to the well, and for each WEC applicable facility, the total emissions attributable to all permanently shut-in and plugged wells at the facility; and a certification statement by the designated representative for the WEC obligated party that all identified wells were closed in accordance with state, local, and Federal requirements. We are proposing that the information included in the report would be subject to the general recordkeeping requirements for part 99, meaning these records must be retained for 5 years following the WEC filing year of the exemption such that they can be made available to the EPA for inspection and review.

The EPA requires this information for the verification of exemption eligibility and of exempted emission quantity. Reported information will be used to conduct verification as discussed in section III.A.4., and reported information, records and other information as applicable will be used to conduct any auditing that occurs under section III.E.1.

The EPA seeks comment on the reporting and recordkeeping requirements for the exemption for emissions from wells that are permanently shut-in and plugged. We seek comment on whether additional information should be collected or retained to allow for verification of the quantity of emissions eligible for the exemption.

III. General Requirements of the Proposed Rule

A. WEC Reporting Requirements

1. Required Reporters

The WEC obligated party would be required to submit a WEC filing annually by March 31 that would include data collected from each WEC applicable facility of which it (the WEC obligated party) is comprised as of December 31 of each reporting year. The WEC filing would provide the data necessary for the EPA to assess and verify the WEC obligation including certain part 98 emissions information and netting, as applicable, as well as supporting documentation for any WEC applicable facility exemptions.

2. Reporting Deadlines

As required under the CAA sections 136(c) and (e), the assessment of the first WEC will be based on data collected under subpart W of the GHGRP beginning on January 1, 2024. We are proposing in 40 CFR 99.5 that the first WEC filing would be due March 31, 2025, and would be required to be submitted annually by March 31 thereafter, as applicable. We have proposed the March 31 reporting deadline under this action for the purpose of quantifying WEC such that the information reported for part 99 can be done in coordination with and on the same schedule as (*i.e.*, by March 31 of the calendar year following the reporting year) the information reported under subpart W.

The EPA is proposing that final revisions to the first WEC filing, with the exception of resubmissions to provide CAA section 111(b) or (d) compliance reports or revisions to previously reportd compliance reports for the purposes of the regulaltory compliance exemption, would be due by November 1, 2025, and would be required to be submitted annually by November 1 thereafter, as applicable (see section III.A.4. of this preamble for discussion and request for comment on this deadline).

3. Submission of the WEC Filing

The EPA proposes that each WEC filing must be submitted electronically in accordance with the requirements of 40 CFR 99.6 and in a format specified by the Administrator.

As noted previously in this section of the preamble, the EPA proposes that each WEC obligated party will submit a WEC filing annually. The WEC filing content we are proposing is expected to provide the data necessary to complete the WEC calculations as described previously in the preamble. We are proposing WEC filing reporting requirements to cover general company information including physical address, email, telephone number, list of associated WEC applicable facilities and their identifying information (*e.g.*, part 98, subpart W e-GGRT ID), as well as the net WEC emissions calculated in accordance with 40 CFR 99.22 and the WEC obligation as calculated pursuant to 40 CFR 99.23. We are also proposing that each WEC obligated party’s WEC filing include certain information at the WEC applicable facility level. Specifically, we are proposing that for each WEC applicable facility that comprises the WEC obligated party, the reporting requirements would cover facility-level information including the facility's eGGRT ID, the facility's industry segment(s), the facility's waste emissions threshold calculated in accordance with 40 CFR 99.20, and the facility's WEC applicable emissions calculated in accordance with 40 CFR 99.21.

The EPA seeks comment on these reporting and recordkeeping requirements (e.g., date of WEC filing and payment for the first year). We seek comment on whether additional information should be reported to EPA or retained by the WEC obligated party or WEC applicable facility to allow for verification of the WEC filing.

The EPA is also proposing reporting requirements for each WEC obligated party related to the three WEC exemptions, which are discussed in sections II.D.1. through 3. of this preamble. Under the proposed approach, the exemptions are only available to WEC applicable facilities that exceed the waste emissions threshold. The EPA therefore proposes that these reporting requirements would only apply to WEC applicable facilities that exceed the waste emissions threshold and are otherwise eligible for the exemption(s). The EPA seeks comment on the reporting requirements for each exemption, as noted in sections II.D.1. through 3. of this preamble.

4. Verification and WEC Filing Revisions

We anticipate that the foundation of the WEC obligated party's WEC filing would be the methane emissions and throughput reported by the WEC applicable facilities in their subpart W reports. As specified in § 98.3(f) and (h) of this chapter, part 98 currently includes a verification process and resubmission process for resolving substantive error(s)[40] in reporting. These errors are either found through self-discovery by the WEC obligated party or are found by the EPA during the verification process. In part 98, errors must be resolved within 45-days from discovery or notification of the error by the EPA. The EPA may grant a 30-day extension request if the request is timely, such that a total of 75 days may be provided for complete issue resolution. Additional extensions may be approved by the Administrator in specified limited circumstances. Resolution is either made by report revision and resubmission or by providing an adequate demonstration that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error. Upon satisfying these requirements, the EPA designates the part 98 report as verified. If the requirements in § 98.3 of this chapter are not satisfied, the EPA considers the part 98 report unverified.

We are proposing that the verification status of the WEC applicable facility with respect to the reporting in subpart W part 98 would be considered by the EPA when determining the verification status of the part 99 filing because the subpart W data would be the cornerstone of the WEC. In effect, a WEC filing may not achieve verified status until all errors associated subpart W reports that impact total WEC are corrected. For example, if the subpart W part 98 report of one WEC applicable facility contains errors related to reported emissions or throughput that affect total WEC, the EPA could by extension consider the WEC filing of the WEC obligated party that includes that WEC applicable facility to be unverified. However, there may

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[40] 40 CFR 98.3(h)(3): A substantive error is an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified.

also be situations in which an unverified subpart W part 98 report does not impact the ability to accurately calculate a WEC obligated party’s WEC obligation. In these circumstances, the proposed approach would allow the EPA to verify a WEC obligated party’s part 99 report even if the part 98 report of a WEC applicable facility associated with the WEC obligated party remained unverified.

Separately, there are elements of the part 99 filing that would not be tied to the subpart W report, such as the calculation of the WEC including netting and any exemption information. We are proposing to implement a similar verification procedure under part 99 to that which exists under part 98. In implementing the verification of information submitted under part 99, the EPA envisions a two-step process. First, we propose to conduct an initial centralized review of the data that would help assure the completeness and accuracy of data. Second, the EPA intends to notify WEC obligated parties of potential errors, discrepancies, or make inquiries as needed concerning the WEC filing. Specifically for this rulemaking, we anticipate that there could be errors or clarifications with respect to the supporting documentation and quantification of emissions associated with exemptions from the WEC, which may require EPA review to evaluate and confirm their validity and accuracy. The part 99 verification review would identify issues resulting from the calculation of WEC based on verified subpart W GHGRP reports and verified WEC filings to the extent possible. A thorough discussion of the separate process for unverified reports and approach for reassessment of WEC obligation due to resubmissions is discussed in section III.B. of this preamble.

We are proposing provisions that would require a WEC obligated party to resubmit their WEC filing within 45-days of either being contacted in writing by the EPA notifying them of the presence of a substantive error in their WEC filing or by self-discovering that a previously submitted WEC filing contains one or more substantive errors (except as described later in this section), or within 75 days if granted a 30-day extension per 40 CFR 99.7(e)(4). For the purposes of part 99, we are proposing to consider a substantive error to be an error that impacts the Administrator's ability to accurately calculate the WEC obligated party's obligation, which may include, but would not be not limited to, the list of WEC applicable facilities associated with a WEC obligated party and corresponding data reported in each listed WEC applicable facility part 98 report(s), emissions associated with exemptions, and supporting information for each exemption to demonstrate its validity. We are proposing that the revised WEC filing must correct all substantive errors or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error.

We are also proposing that if a WEC applicable facility revises and resubmits their part 98 report, which results in impacts on the WEC calculations, the WEC obligated party would also be required to submit a revised WEC filing that includes the number of corrections and information detailing the correction(s) made. In the event that a subpart W report revision results in a change in the applicability of part 99 to the facility, under the proposed provisions the WEC obligated party would either submit a WEC filing adding or removing any facilities, as appropriate. As described in the paragraph below, with the exception of resubmissions to provide

CAA section 111(b) or (d) compliance reports or revisions to previously reported compliance reports for the purposes of the regulatory compliance exemption, the EPA is proposing that part 99 resubmissions would only be allowed up to November 1 of the year following the reporting year. Any part 98 resubmissions after this date that impact WEC calculations would not be required to be resubmitted in a revised WEC filing; facilities could continue to resubmit data under subpart W at any time. Resubmissions related to CAA section 111(b) or (d) compliance reports for the purposes of the regulatory compliance exemption must be made as discussed in section II.D.2.g. of this preamble.Under subpart W, facilities may resubmit data for historic reporting years via e-GGRT for the most recent five reporting years (e.g., submit updates to 2019 data in 2022). Data resubmission for historic reporting years in the context of the WEC program is extremely complicated due to the potential changes in facility ownership over time and the implications this has on netting of emissions from facilities under common ownership or control. For example, a company or a facility owned by a company in one year may be owned in whole or in part by one or multiple different companies the next year. With such changes occurring annually to multiple facilities across multiple owners and operators with more than one facility under common ownership or control, there is no practical means of incorporating resubmitted data for historic reporting years in the WEC program. This would require the EPA to engage in a potentially constant series of WEC recalculations and associated invoicing or refunds. The EPA therefore proposes a deadline of November 1 for each year, after which time no WEC filings could be resubmitted. For example, resubmissions of data initially reported by March 31, 2025, used to assess WEC for the 2024 reporting year, would be required to be submitted by November

1, 2025. This proposed approach would not allow resubmissions for historic reporting years for WEC filings, even if their corresponding subpart W data was resubmitted for historic reporting years for purposes of subpart W. Subpart W facilities would continue to be subject to part 98 existing requirements for resubmitting data for previous reporting years, but any data resubmitted under part 98 after November 1 of the calendar year following the respective reporting year would not be considered for the purposes of WEC under part 99. This deadline would apply to all WEC applicable facilities, including those with data verified by EPA. The EPA's proposed approaches for WEC filing requirements and data verification are intended to incentivize complete and accurate WEC filings under part 99, and thus corresponding reporting of complete and accurate data under part 98, by March 31 of each year. As a result, the EPA expects that there will be little need to resubmit data after this initial reporting deadline, and the seven months between March 31 and the proposed final deadline of November 1 would give facility owners or operators sufficient time to make any resubmissions. The EPA proposes that it would retain the right to reevaluate WEC obligations in WEC filings after November 1 (e.g., as part of an EPA audit of facility data). Similarly, the November 1 deadline would not apply to adjustments to WEC obligations resulting from the process to resolve unverified data, proposed at 40 CFR 99.8, should that resolution occur after November 1.

The EPA requests comment on the proposed approach of setting a deadline for WEC resubmissions under part 99 and in doing so not allowing data resubmissions for the WEC filing for previous historic reporting years. The EPA requests comment on the November 1 deadline and options for alternative deadlines. The EPA also requests comment on alternative approaches that would allow data resubmissions for historic reporting years under the WEC program, as well as comment on how such changes would be incorporated into netting for historic reporting years.

B. Remittance and Assessment of WEC

We are proposing that each WEC obligation payment must be submitted electronically in accordance with the proposed requirements of 40 CFR 99.6 and in a format specified by the Administrator as part of the submission of the WEC filing (*i.e.*, by March 31 each year covering the preceding reporting year).

For the purposes of ensuring timely payment of the WEC, the EPA is proposing financial sanctions under 40 CFR 99.10 of subpart A, pursuant to the authority included in the Federal claims provision at 31 U.S.C. 3717. These penalties would apply to delinquent WEC payments. Under 31 U.S.C. 3717, there are interest, penalties, and costs that may be imposed on outstanding or delinquent debts arising under a claim owed by a person to the U.S. Government. Specifically, under 31 U.S.C. 3717(a)(1), agencies shall charge a minimum annual rate of intereston an outstanding debt on a United States Government claim owned by a person.[41] Under the EPA’s implementing Policy Number 2540-9-P2, accounts are considered delinquent when the EPA does not receive payment by the due date specified on a bill or invoice (*i.e.*, for the

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[41] This rate of interest is known as the Current Value of Funds Rate, or CVFR, and is published prior to November 30th of each year by Treasury. The CVFR is based on the weekly average of the Effective Federal Funds Rate, less 25 basis points, for the 12-month period ending September 30th of each year, rounded to the nearest whole percent. This rate may be revised on a quarterly basis if the annual average, on a moving basis, changes by 2 percentage points or more.

WEC obligation at the time of submission of the WEC filing). The EPA is proposing to cite this Federal claims interest charge authority as the first tier of WEC payment sanctions.

Second, under 31 U.S.C. 3717(e)(1), agencies must collect an additional penalty charge of not more than six percent per year for failure to pay any part of a debt more than 90 days past due, as well as additional charge to cover the cost of processing delinquent claims. Under Policy Number 2540-9-P2, the EPA Finance Centers are responsible for issuing demand notices and conducting collection efforts for the Agency. The EPA Finance Centers would assess interest, handling, and penalty charges in 30-day increments for late payments and would assess the 6 percent penalty with the 3rd demand letter or notice.

The EPA therefore proposes to include this additional 6 percent non-payment penalty charge for WEC debts that are more than 90 days past due. This would be the second tier of sanction authority under this proposal’s set of payment sanctions and would be implemented if the first tier of interest charges is not effective in causing a delinquent WEC obligated party to make their payments current. The EPA seeks comment on its proposed approach for applying interest to late WEC fee payments.

Additionally, for WEC obligated parties that fail to submit their annual WEC filing by the deadline discussed in section III.A.2. of this preamble, the EPA is proposing a daily penalty no greater than the rate associated with 42 U.S.C. 7413(d)(1) specified in Table 1 of 40 CFR 19.4, as amended. The EPA Finance Centers would assess interest, handling, and penalty charges in 30-day increments. We are proposing that the assessment of this penalty would begin on the date that the WEC filing was considered past due (*i.e.*, April 1st) and continue until such time that the WEC filing is submitted and certified by the WEC obligated party. The EPA requests comment on its proposed approach of establishing a daily penalty for unsubmitted WEC filings.

1. Process for Reassessing WEC for WEC Filings Resubmitted After the Initial Waste Emission Charge Has Been Assessed

As discussed in section III.A.4. of this preamble, WEC obligated parties may need to resubmit their WEC filings and WEC applicable facilities may need to resubmit their GHGRP reports. These resubmittals have the potential to result in recalculation of the WEC obligation for the WEC obligated party. As discussed in section III.A.4. of this preamble, the EPA proposes that data resubmissions for the previous reporting year would be required to be submitted by November 1 in order to be considered for WEC recalculations, with the exeption of resubmissions related to CAA section 111(b) or (d) compliance reports for the purposes of the regulatory compliance exemption. If the recalculated WEC obligation is less than the original WEC obligation owed by the WEC obligated party, we propose that the EPA would authorize a refund to the WEC obligated party equal to the difference in WEC obligation. If the recalculated WEC obligation is greater than the original WEC obligation owed by the WEC obligated party, the EPA would charge the WEC obligated party for the remaining balance of the WEC, including any assessed fees or penalties.[42] To encourage careful attention to detail and reduce the need for WEC filing revisions, we are proposing to charge a daily interest rate for any revised

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[42] We propose that WEC obligated parties would be subject to the financial sanctions proposed in 40 CFR 99.10 for any delinquent payments of the revised WEC invoice(s), as discussed in section III.B. of this preamble.

WEC filing that results in additional WEC being owed. As proposed in 40 CFR 99.8, this daily interest rate would be assessed from April 1st (*i.e.*, the day after the submission deadline) until such time that a resubmitted WEC filing and payment, that is subsequently verified by the EPA, is certified by the designated representative. We propose a daily interest rate equal to theCurrent Value of Funds Rate, consistent with 31 U.S.C. 3717(a). The EPA proposes that payment for any additional WEC, including assessed interest, would made with the resubmitted WEC filing.

The EPA seeks comment on the proposed approach for resubmitted WEC filings, including the application of daily interest rate for revised WEC filings that result in additional WEC being owed.

2. Process for Assessing WEC for Unverified Part 99 Filings

As discussed in section III.A.4. of this preamble, the EPA’s verification review process ideally ends with the resolution of identified potential errors through either correction and resubmission of facilities’ reports or justification provided through correspondence with reporters that no substantive error exists. When WEC applicable facilities or WEC obligated parties do not provide appropriate information to resolve the errors in their part 98 or part 99 data after 45 days (with the possibility of a 30-day extension) of either being contacted in writing by the EPA notifying them of the presence of a substantive error or by self-discovering that a previously submitted part 98 report or WEC filing contains one or more substantive errors, the EPA considers their WEC filing to be unverified.

If a WEC filing is unverified but the EPA is able to correct the error(s) based on reported data, we propose that the EPA will recalculate the WEC using available information and provide an invoice or refund to the WEC Obligated Party within 60 days of determining a WEC filing to be unverified. If the WEC Obligated Party resubmits a WEC filing within that timeframe, the EPA would either accept the resubmission, or take the resubmission into account when calculating the WEC. In cases where the EPA is unable to calculate the WEC with available information, the WEC Obligated Party may be required to undergo a third-party audit. The third-party auditor must review records kept by the WEC Obligated Party, quantify the WEC with available information and in accordance with the requirements of this part, and submit the updated WEC calculations and supporting data to the EPA. The EPA would then take that information into consideration and calculate the WEC and provide an invoice to the WEC Obligated Party. Third-party audits may be required to be arranged by and conducted at the expense of the WEC obligated party.

A WEC obligated party would be required to pay an invoice received from the EPA for any updated WEC obligation by the specified due date, or within 30 days of the date of the invoice or bill if a due date is not provided.

The EPA requests comment on the proposed approach for assessing WEC for unverified part 99 reports, including the EPA recalculating WEC when data are available, and the option of requiring third-party auditing of WEC obligated party records when the EPA is not able to recalculate WEC with the available information. The EPA requests comment on an alternative approach that would establish default values (*e.g.*, industry segment-specific methane intensities) that would be conservative in nature and used to calculate WEC applicable emissions from unverified reports until such time that the report becomes verified. The calculated methane emissions from the unverified report(s) would then be included when determining the WEC obligated party's WEC obligation. In this approach, the EPA envisions that similar financial sanctions as those discussed in section III.B.2. of this preamble would be applied until a verified report is submitted and certified by the WEC applicable facility. We also seek comment on additional gap-filling approaches for unverified GHGRP reports. In addition, the EPA seeks comment on an approach for unverified reports that would apply daily penalties on unverified reports, up to the rate associated with U.S. Code citation 42 U.S.C. 7413(d)(1) specified in Table 1 of 40 CFR 19.4, as amended. Under such an approach, the EPA seeks comment on the duration of the penalty (*e.g.*, 3 years or until the report is verified, whichever is sooner).

C. Authorizing the Designated Representative

We are proposing provisions for each affected WEC obligated party to identify a designated representative. We are proposing that each WEC obligated party would each have one designated representative who is an individual selected by an agreement binding on the WEC obligated party. This designated representative would act as a legal representative between the WEC obligated party and the Agency. We are proposing that the designated representative must submit a complete certificate of representation at least 60 days prior to the submission of the first WEC filing made by the WEC obligated party. Additionally, each WEC filing would contain a signed certification by a designated representative of the WEC obligated party. On behalf of the owner or operator, the designated representative would certify under penalty of law that the WEC filing has been prepared in accordance with the requirements of 40 CFR part 99 and that the information contained in the WEC filing is true and accurate, based on a reasonable inquiry of individuals responsible for obtaining the information.

We are also proposing that the designated representative could appoint an alternate to act on their behalf, but the designated representative would maintain legal responsibility for the submission of complete, true, and accurate emissions data and supplemental data. A designated representative or alternate designated representative may delegate one or more “agents.” The agent (*e.g.*, a part 98 subpart W designated representative who can provide facility-specific information) can enter data for a part 99 WEC filing, but is not allowed to submit, certify, or sign a WEC filing.

We are proposing that within 90 days after any change in the WEC obligated party, the designated representative or any alternate designated representative must submit a certificate of representation that is complete under this section to reflect the change.

D. General Recordkeeping Requirements

We are proposing that WEC applicable facilities and WEC obligated parties must retain all required records for at least 5 years from the date of submission of the WEC report for the reporting year in which the record was generated. We are proposing that the records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and auditing. Under the proposed provisions, upon request by the Administrator, the records required under this section must be made available to the EPA. We are proposing that records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, we are proposing that the equipment or software necessary to read the records shall be made available, or, if requested by the EPA, electronic records shall be converted to paper documents. The records that the EPA is proposing that must be retained would include information required to be retained under part 98, specifically subparts A and W, any other information needed to complete the WEC filing, and all information required to be submitted as part of the WEC filing, including any supporting documentation.

E. General Provisions, Including Auditing and Compliance and Enforcement

1. Auditing Provisions

We are proposing that the EPA may conduct on-site audits of facilities, as indicated in 40 CFR 99.7(c). Under the proposed general recordkeeping provision at 40 CFR 99.7(d), the records generated under this part would be available to the EPA during an on-site audit as the records must be recorded in a form that is suitable for expeditious inspection and review, and must be made available to the EPA upon request. The on-site audits may be conducted by private auditors contracted by the EPA or by Federal, State or local personnel, as appropriate, and may be required to be arranged by and conducted at the expense of the WEC obligated party.

2. Compliance and Enforcement

We are proposing that any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (*42 U.S.C. 7414*) and section 136 (*42 U.S.C. 7436*). A violation would include but is not limited to failure to submit, or resubmit as required, a WEC filing, failure to collect data needed to calculate the WEC charge (including any data relevant to determining the applicability of any exemptions), failure to retain records needed to verify the amount of WEC charge, providing false information in a WEC filing, and failure to remit WEC payment. As proposed at 40 CFR 99.4(b), it is a violation to fail to authorize a designated representative for a WEC obligated party. In the case of a facility with more than one owner or operator, failure to select a WEC obligated part would constitute a violation on the part of each owner or operator, as proposed at 40 CFR 99.4. Each day of a violation would constitute a separate violation.

IV. Proposed Confidentiality Determinations for Certain Data Reporting Elements

A. Overview and Background

In this action, the EPA is proposing to require WEC obligated parties to report the general information described in section III.A.3. of this preamble and the information specific to any applicable exemptions as described in sections II.D.1. through 3. of this preamble. This information is necessary for the EPA to verify the contents of the WEC filing, including confirming that all of the required WEC applicable facilities were included, each WEC applicable facility is eligible for any exemptions that were applied, and the WEC applicable emissions and the amount of the WEC obligation were calculated correctly. As explained in the remainder of this section, the EPA is proposing that nearly all of the data reported would be either emission data or otherwise ineligible for confidential treatment. The information that may be eligible for confidential treatment would be information included in supporting documentation required for eligible exemptions or additional information provided in software comments fields.

Section 114(c) of the CAA requires that “[a]ny records, reports, or information obtained under [CAA section 114(a)] shall be available to the public, except that upon a showing satisfactory to the Administrator by any person that records, reports, or information, or particular part thereof, (other than emission data) . . . if made public, would divulge methods or processes entitled to protection as trade secrets . . ., the Administrator shall consider such record, report, or information or particular portion thereof confidential. . . .” Thus, the CAA begins with a presumption that information submitted to the EPA may be disclosed to the public. It then provides a narrow exception to that presumption for information that “if made public, would divulge methods or processes entitled to protection as trade secrets. . . .” Section 114(c) of the CAA narrows this exception further by excluding “emission data” from the category of information eligible for confidential treatment. The EPA has interpreted CAA section 114(c) to afford confidential treatment to both trade secrets and confidential business information that are not emission data (40 FR 21987, 21990 (May 20, 1975)).

While the CAA does not define “emission data,” the EPA has done so by regulation at 40 CFR 2.301(a)(2)(i). Emission data means, with reference to any source of emissions of any substance into the air—

(A) Information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source (or of any pollutant resulting from any emission by the source), or any combination of the foregoing;

(B) Information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of the emissions which, under an applicable standard or limitation, the source was authorized to emit (including, to the extent necessary for such purposes, a description of the manner or rate of operation of the source); and

(C) A general description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources (including, to the extent necessary for such purposes, a description of the device, installation, or operation constituting the source).

Further, in a 1991 EPA notice of policy (56 FR 7042, February 21, 1991), the EPA stated that certain data fields constitute “emission data” and therefore cannot be withheld as confidential. The 1991 document indicated that while confidentiality determinations are typically made on a case-by-case basis, some kinds of data will always constitute emission data within the meaning of CAA section 114(c). The document listed several data fields that EPA considered to be emission data including facility identification data (*e.g.*, facility name; address; ownership; Standard Industrial Classification (SIC); emission point, device or operation description information) and emission parameters (*e.g.*, compounds emitted; origin of emissions; emission rate, concentration, release parameters, boiler or process design capacity, emission estimation method). The document clarified that the list of types of information in the document was not exhaustive and that other data might also constitute emission data.

For data that are not “emission data,” the confidentiality determination criteria at 40 CFR 2.208(a) through (d) are as follows:

Determinations issued under §§ 2.204 through 2.207 shall hold that business information is entitled to confidential treatment for the benefit of a particular business if:

(a) The business has asserted a business confidentiality claim which has not expired by its terms, nor been waived nor withdrawn;

(b) The business has satisfactorily shown that it has taken reasonable measures to protect the confidentiality of the information, and that it intends to continue to take such measures;

(c) The information is not, and has not been, reasonably obtainable without the business's consent by other persons (other than governmental bodies) by use of legitimate means (other than discovery based on a showing of special need in a judicial or quasi-judicial proceeding); and

(d) No statute specifically requires disclosure of the information.

In *Food Marketing Institute* v. *Argus Leader Media*, 139 S. Ct. 2356 (2019) (hereafter referred to as *Argus Leader*), the U.S. Supreme Court issued an opinion addressing the meaning of the word "confidential" in Exemption 4 of the Freedom of Information Act, 5 U.S.C. Section 552(b)(4)(2012 and Supp. V. 2017) stating that "confidential" must be given its "ordinary" meaning, which is information that is "private" or "secret." As a result, starting with the date of the *Argus Leader* ruling, the EPA no longer assesses data elements using the rationale of whether disclosure will cause a likelihood of substantial competitive harm when making confidentiality determinations. Instead, the EPA assesses whether the information is customarily and actually treated as private by the reporter and whether the EPA has given an assurance at the time the information was submitted that the information will be kept confidential or not confidential.

B. Proposed Confidentiality Determinations

Pursuant to CAA section 114(c), the EPA is proposing to make categorical emission data and confidentiality determinations in advance through this notice and comment rulemaking for the categories of information in these proposed reports under part 99. We describe the proposed emission data categories and confidentiality determinations for the reported information, as well as the basis for such proposed determinations, in this section. This approach is similar to the approach we have taken for the GHGRP under 40 CFR part 98 (see 75 FR 39094, July 7, 2010, and 75 FR 30782, May 26, 2011, for more information).

The determinations the EPA is proposing in this rulemaking, if finalized, would serve as notification of the Agency's decisions concerning: (1) the categories of information the Agency will not treat as confidential because it is emission data; (2) the information that is not emission data but is not entitled to confidential treatment; and (3) the information that the submitter may claim as confidential but will remain subject to the existing 40 CFR part 2 process. In responding to requests for information not determined in this proposal to be emission data or otherwise not entitled to confidential treatment, we propose to apply the default case-by-case process found in 40 CFR part 2.

The emission data and confidentiality determinations proposed in this rulemaking are intended to provide consistency in the treatment of the information collected by the EPA as part of the proposed WEC filings. The EPA anticipates that making these determinations in advance through this rulemaking will provide predictability and transparency for both information requesters and submitters.

The categories of information that we are proposing to determine to be emission data in this action are:

(1) Methane emissions;

(2) Calculation methodology; and

(3) Facility and unit identifier information.

The EPA is proposing to group types of information (data elements) that the Agency is proposing to require WEC obligated parties to submit under part 99 that would be considered emission data into these three categories based on their shared characteristics. For the sake of organization, for any information that logically could be grouped into more than one category, we have chosen to label information as being in just one category where we think it fits best. This approach will reduce redundancy within the categories that could lead to confusion and ensure consistency in the treatment of similar information in the future. We are requesting comment on the following: (1) our proposed categories of emission data; and (2) our placement of each data element under the category proposed.

For reporting elements that the EPA does not designate as “emission data,” the EPA is proposing to assess each individual reporting element according to the *Argus Leader* criteria (*i.e.*, whether the information is customarily and actually treated as private by the submitter) and 40 CFR 2.208(a) through (d). Therefore, we are not proposing to establish categories and categorical confidentiality determinations for information that is not “emission data.” However, we are proposing descriptions of the type of information that would not be eligible for confidential treatment in 40 CFR 99.13(b), including certain information demonstrating compliance with standards and information that is publicly available. We are also proposing in 40 CFR 99.13(c) through (e) to specify certain data elements and types of information that would be subject to the process for confidentiality determinations in 40 CFR part 2. The proposed provisions in 40 CFR 99.13(b) would establish the proposed confidentiality determinations of the proposed data elements in part 99 and would also provide clarity and ensure consistent treatment of new or substantively revised data elements if the content of the WEC filing is amended in a future rulemaking. Sections IV.B.2. and 3. of this preamble describe these proposed provisions, and our assessment of each individual reporting element that we are proposing is not “emission data.” We are requesting comment on the proposed Agency determinations that information described in those sections of the preamble are not entitled to confidential treatment.

1. Emission Data

We are proposing to establish in 40 CFR 99.13(a) that certain categories of information the EPA would collect in the proposed WEC filings are information that meets the regulatory definition of emission data under 40 CFR 2.301(a)(2)(i). The following sections describe the categories of information we are proposing to determine to be emission data, based on application of the definition at 40 CFR 2.301(a)(2)(i) to the shared characteristics of the information in each category and our rationale for each proposed determination.

a. Information Necessary to Determine the Identity, Amount, Frequency, Concentration, or Other Characteristics of Emissions Emitted by the Source

Under 40 CFR 2.301(a)(2)(i)(A), emission data includes “[i]nformation necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source (or of any pollutant resulting from any emission by the source), or any combination of the foregoing[.]" We are proposing that the following categories of information are emission data under 40 CFR 2.301(a)(2)(i)(A):

(1) Methane emissions; and

(2) Calculation methodology.

Methane emissions. Data elements included in the Methane emissions data category are the net WEC emissions, facility waste emissions thresholds, industry segment waste emissions thresholds for each applicable industry segment within the facility (if more than one industry segment applies), and WEC applicable emissions, as well as the quantities of methane emissions that the WEC obligated party calculates should be exempted due to unreasonable delay and wells that were permanently shut-in and abandoned. The EPA proposes to determine that the emissions at each reporting level constitute "emission data." These data elements are information regarding the identity, amount, and frequency of any emission emitted by the WEC applicable facility, and, therefore, they are "emission data." As discussed in section IV.A. of this preamble, in the 1991 EPA notice of policy (56 FR 7042, February 21, 1991), the EPA identified, without attempting to be comprehensive, data elements that the EPA considered to constitute emission data. The 1991 document lists the "Emission type (*e.g.*, the nature of emissions, such as CO_2, particulate or a specific toxic compound, and origin of emissions such as process vents, storage tanks or equipment leaks)" and "Emission rate (*e.g.*, the amount released to the atmosphere over time such as kg/yr or lbs/yr)" as data that are not entitled to confidential treatment and are, therefore, releasable to the public. Our proposed determination for this data category is consistent with the 1991 document. It is also consistent with the determination for a similar category in the GHGRP under 40 CFR part 98.

Calculation methodology. The data element included in this category is the method used to determine the quantity of methane emissions that the WEC obligated party calculates should be exempt due to an unreasonable permitting delay and the method used to determine the equipment leaks emissions attributable to a plugged well. Most of the necessary calculations in part 99 do not include multiple equations or approaches that could be selected by a WEC obligated party, and in those cases, the calculation methodology used is readily apparent for any WEC obligated party. Calculations for the exemptions for unreasonable delay and plugged wells do include multiple equations that facilities may use under different circumstances.

The EPA proposes to determine that the data elements in the Calculation methodology category are “emission data” under 2.301(a)(2) because they are “information necessary to determine . . . the amount” of emissions emitted by the source. The method used to calculate emissions is emission data under 40 CFR 2.301(a)(2) because it is information necessary for the WEC obligated party to calculate the emissions and for the EPA and the public to verify that an appropriate method was used. As discussed in section IV.A. of this preamble, the 1991 EPA notice of policy provided a list of information that the EPA considered to constitute “emission data” under 40 CFR 2.301(a)(1)(2)(i). That list includes the “emission estimation method (*e.g.*, the method by which an emission estimate has been calculated such as material balance, source test, use of AP-42 emission factors, etc.),” which is the same type of data element as those that the EPA is proposing to include in this data category. Our proposed determination for this data category is consistent with the 1991 document. It is also consistent with the determination for a similar category in the GHGRP under 40 CFR part 98.

b. Information that is Emission Data Because it Provides a General Description of the Location and/or Nature of the Source to the Extent Necessary to Identify the Source and to Distinguish it from other Sources

Under 40 CFR 2.301(a)(2)(i)(C), emission data includes “a “[g]eneral description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources (including, to the extent necessary for such purposes, a description of the device, installation, or operation constituting the source).” We are proposing that the data elements in the Facility and unit identifier information category of information are emission data under 40 CFR 2.301(a)(2)(i)(C).

The proposed part 99 regulations would require WEC obligated parties to report in the WEC filing information needed to identify each facility as well as specific emission units (affected facilities) and/or well-pads associated with an exemption. Facility-identifying information must be reported for all facilities as specified in 40 CFR part 99, subpart A. Affected facility-specific identifying information is required for the regulatory compliance exemption. Well-pad-specific identifying information is reported if required by an applicable exemption for onshore petroleum and natural gas production facilities.

Data elements in this category would include the following data elements required under 40 CFR part 99, subpart A to be included in each annual WEC filing: WEC obligated party company name and address, the name and contact information for the designated representative of WEC obligated party, and a signed and dated certification statement of the accuracy and completeness of the report, which is provided by the designated representative of the owner or operator. The proposed part 99 regulations would also require that the filing include specific information about each facility covered by the annual WEC filing, including the e-GGRT ID number and the industry segment. For each exemption, the facility and unit identifier information category would include (as applicable) the facility identifier, the well-pad and/or well identifier reported under subpart W (if applicable), other facility or affected facility identifiers used to identify the facility/sources in other EPA systems (specifically, the ICIS-AIR ID or Facility Registry Service (FRS) ID and the EPA Registry ID from the Compliance and Emissions Data Reporting Interface (CEDRI)), emission source-specific methane mitigation activities impacted by an unreasonable permitting delay, and exemption-specific certification statements.

As discussed in section IV.A. of this preamble, emission data must be available to the public and is not entitled to confidential treatment under CAA section 114(c). “Emission data” is defined in 40 CFR 2.301(a)(2)(i)(C) to include “[a] general description of the location and/or nature of the source to the extent necessary to identify the source and to distinguish it from other sources . . . .” Consistent with this definition of emission data, the EPA considers facility and emission unit identifiers to be source information or “information necessary to determine the identity . . . of any emission which has been emitted by the source,” and therefore emission data under 40 CFR 2.301(a)(2)(i). Further, 40 CFR 2.301(a)(2)(i)(A) specifies that emission data includes, among other things, “information necessary to determine the identity, amount, frequency, concentration, or other characteristics (to the extent related to air quality) of any emission which has been emitted by the source. . . .” The EPA considers the term “identity . . . of any emission” as not simply referring only to the names of the pollutants being emitted, but to also include other identifying information, such as from what and where (*e.g.*, the identity of the emission unit) the pollutants are being emitted.

The 1991 EPA notice of policy (discussed in section IV.A. of this preamble) provided a list of data fields that the EPA considered to be emission data. For example, in the 1991 document, the EPA considered that plant name, address, city, State, zip code, emission point or device description, SIC code, and Source Classification Code (SCC) are emission data. Therefore, the public has been on notice that the EPA considers many of the data elements in this data category to be emission data and thus not entitled to confidential treatment. The 1991 document also makes clear that the list of data is not comprehensive and that other data might also constitute emission data. This proposed part 99 determination that these data elements are emission data is consistent with the 1991 policy statement, and also consistent with the Facility and unit identifier information category in the GHGRP under 40 CFR part 98.

2. Reported Information that is Never Entitled to Confidential Treatment.

As noted in section IV.B. of this preamble, we are proposing to assess the confidentiality of each individual part 99 reporting element that is not otherwise designated as emission data in this rulemaking according to the *Argus Leader* criteria (*i.e.*, whether the information is customarily and actually treated as private by the submitter) and 40 CFR 2.208(a) through (d). However, in this action we are proposing descriptions of the type of information that would not be eligible for confidential treatment in 40 CFR 99.13(b), in part to establish the proposed confidentiality determinations of the proposed data elements in part 99 but also to provide clarity and consistency in the event that the content of the WEC filings are amended in a future rulemaking. The WEC obligation is calculated by multiplying the net WEC emissions by a set dollar amount, depending on the reporting year. As explained in section IV.B.1.a. of this preamble, the EPA is proposing to determine that the net WEC emissions are emission data. Therefore, we are proposing that the WEC obligation, which is calculated as the net WEC emissions multiplied by a dollar per ton rate that is prescribed in CAA section 136, would not be eligible for confidential treatment.

We are also proposing that certain information considered to be compliance information in part 99, regardless of whether it is or is not designated as emission data, is still not otherwise eligible for confidential treatment. Compliance information collected under part 99 includes information necessary to demonstrate compliance with the eligibility requirements for the exemptions for unreasonable permitting delay, regulatory compliance, and wells that have been permanently shut-in and plugged. Examples of the information collected include: for the unreasonable delay exemption, the date of the permit request, the estimated date to commence operation if the application had been approved within a set period of months, the first date that offtake to the gathering or transmission infrastructure from the implementation of methane emissions mitigation occurred once the application was approved, the beginning and ending date for which the eligible delay limited the offtake of natural gas associated with methane emissions mitigation activities, information on all applicable local, state, and Federal regulations regarding flaring emissions and the facility's compliance status for each, and other compliance information related to gathering or transmission infrastructure; for the regulatory compliance exemption, copies of reports and other evidence of compliance with NSPS OOOOb or a state, Tribal, or Federal plan under 40 CFR part 62; and for the plugged well exemption, the date a well was permanently shut-in and plugged and the statutory citation for the requirements that were followed for that process. Operating and construction permits are available to the public through the State issuing the permits (as the delegated authority of the EPA), generally either through an online information system or website, or upon request to the state agency issuing the permits. These permits are expected to contain information about the type and size of process equipment operated at a facility, control devices or other measures undertaken to reduce emissions from each process, and the emission standards to which the facility is subject (including Federal standards as well as state or local standards). Reports submitted by owners and operators of facilities subject to NSPS OOOOb or a state, Tribal, or Federal plan under 40 CFR part 62 are available through the EPA's online repository "WebFIRE." See *https://www.epa.gov/electronic-reporting-air-emissions/webfire*. Finally, well-specific information, including age, production rate, and operating status, is publicly available through state oil and gas commissions and/or state databases as well as sources such as Enverus. Because this information is already publicly available, it would not be eligible for confidential treatment.

The EPA is also proposing in 40 CFR 99.13(b)(3) that any other information that has been published and made publicly available, including the publicly available reports submitted under the GHGRP and information on websites, would not be eligible for confidential treatment.

Information that is publicly available does not meet the criteria for information entitled to confidential treatment specified in 40 CFR 2.208(c). This proposed paragraph 40 CFR 99.13(b)(3) would specify an additional type of information that would not be eligible for confidential treatment when evaluating the confidentiality of supporting documentation submitted as described in proposed 40 CFR 99.13(c) or (d) (see section IV.B.3. for additional information on supporting documentation).

3. Information for Which the EPA is Not Proposing a Confidentiality Determination

This section describes information for which the EPA is not proposing a confidentiality determination. The EPA would initially treat this information as confidential upon receipt, if the submitter claimed it as such, until a case-by-case determination is made by the Agency under the 40 CFR part 2 process.

We do not expect emission data to be submitted in supporting documentation, but we are proposing that information in supporting documentation as described in proposed 40 CFR 99.13(c) (*i.e.*, information not listed in proposed 40 CFR 98.13(a) or (b) as not eligible for confidential treatment) would be treated as confidential until a case-by-case determination is made under the 40 CFR part 2 process. The EPA is also proposing that information provided in software comments fields as described in proposed 40 CFR 99.13(d) would not be eligible for confidential treatment if it is listed in proposed 40 CFR 98.13(a) or (b) as not eligible for confidential treatment. Otherwise, the EPA would treat the information as confidential until a case-by-case determination is made under the 40 CFR part 2 process, as specified in proposed 40 CFR 99.13(c). The EPA recognizes that supporting documentation and reporter comments may include information that is sensitive or proprietary, such as detailed process designs or site plans. Because the exact nature of this documentation cannot be predicted with certainty, the EPA proposes to make case-by-case confidentiality determinations under CAA section 114(c) for any supporting documentation or comments claimed confidential by applicants either upon receipt of such information or upon a request for such information after receipt.

C. Proposed Amendments to 40 CFR Part 2

As previously discussed, pursuant to CAA section 114(c), the EPA must make available to the public data submitted under part 99, except for data (other than emission data) that are considered confidential under CAA section 114(c). Accordingly, the EPA may release part 99 data without further notice after submission to the EPA in accordance with the EPA’s determinations of their confidentiality status in the final rule. Specifically, the EPA may release part 99 data that are determined in the final rule to be emission data or not otherwise entitled to confidential treatment under CAA section 114(c) (*i.e.*, “non-CBI”). For data elements that we determine to be entitled to confidential treatment under CAA section 114(c), the EPA would release or publish such data only if the information can be aggregated in a manner that would protect the confidentiality of these data at the facility level. Existing regulations in 40 CFR part 2, subpart B set forth procedural steps that the EPA must follow before releasing any information, either on the Agency’s own initiative or in response to requests made pursuant to FOIA. In particular, the EPA is generally required to make case-by-case confidentiality determinations and to notify individual reporters before disclosing information that businesses have submitted with a confidentiality claim. As discussed in section IV.B of this preamble, in light of the voluminous data the EPA receives under subpart W of part 98 and the multiple procedural steps required under 40 CFR part 2, subpart B, the EPA would not be able to make part 99 data (determined to be emission data or non-CBI) publicly available in a timely fashion if it were required to make separate confidentiality determinations based on each submitter's individual claim of confidentiality.

To facilitate timely release of GHG data collected under part 99 that are emission data or non-CBI, the EPA proposes to amend 40 CFR 2.301, Special rules governing certain information obtained under the Clean Air Act. Specifically, the EPA is proposing to revise 40 CFR 2.301(d) to specify that the special rules for data submitted under part 98 would also apply to part 99. Under the proposed amendment, the EPA may release part 99 data that are determined to be emission data or information determined to be not entitled to confidential treatment upon finalizing the confidentiality status of these data. Consistent with the 40 CFR part 2 procedures, the approach proposed in this rulemaking would provide the WEC obligated party an opportunity to justify and substantiate any confidentiality claim they may have for the data they are required to submit (except for emission data and other data not entitled to confidential treatment pursuant to CAA section 114(c)). In addition, WEC obligated parties have the benefit of seeing the EPA's rationales and analyses prior to submitting any justification, information that they would not otherwise have under the current 40 CFR part 2 procedures. As more fully explained in section IV.E of this preamble, the WEC obligated party must provide comment explaining why it disagrees with the rationale provided by the EPA for each particular data element it intends to claim confidential and must provide information to explain how the business customarily and actually treats the information as confidential. The EPA will consider comments received on this proposal before finalizing the confidentiality determinations.

The EPA solicits comment on the proposed amendments to 40 CFR 2.301(d), Special rules governing certain information obtained under the CAA for data submitted under part 99.

D. Proposed Changes to Confidentiality Determinations for Data Elements Reported Under Subpart W

The industry segment waste emissions thresholds are calculated pursuant to 40 CFR 99.20. Except for facilities in the Offshore Petroleum and Natural Gas Production industry segment or the Onshore Petroleum and Natural Gas Production industry segment that have no natural gas sent to sale, each threshold is calculated by multiplying the specified natural gas throughput for that industry segment by two constant values, the density of methane and the industry segment-specific methane intensity threshold (as summarized in Table 2 of this preamble). As noted in section IV.B.1.a. of this preamble, the EPA is proposing that the facility waste emissions thresholds and industry segment waste emissions thresholds are emission data and would therefore be made publicly available. For two industry segments, Onshore Natural Gas Processing and Onshore Natural Gas Transmission Compression, throughput quantities similar to those specified in the industry segment waste emissions threshold calculations have historically not been made publicly available under subpart W. However, for WEC applicable facilities, once the industry segment-specific waste emissions thresholds are made publicly available, the throughputs can be calculated based on available information.

Therefore, the EPA is proposing to address confidentiality determinations for two subpart W data elements as part of this rulemaking. For the Onshore Natural Gas Processing industry segment, a new data element was proposed as part of 2023 Subpart W Proposal, the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year, in thousand standard cubic feet, reported under proposed § 98.236(aa)(3)(ix). The EPA made a final determination in 79 FR 70352 (November 25, 2014) that the quantity of natural gas received at the gas processing plant in the calendar year (reported under 40 CFR 98.236(aa)(3)(i)) and the quantity of processed (residue) gas leaving the gas processing plant (reported under 40 CFR 98.236(aa)(3)(ii)), should be maintained as confidential. As explained in 79 FR 70352 (November 25, 2014), the reporting of this information to the Energy Information Administration is less frequent than required under subpart W, and the EPA had not identified any reliable public sources of the quantity of residue gas produced. In the June 2023 memorandum *Proposed Confidentiality Determinations and Emission Data Designations for Data Elements in Proposed Revisions to the Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems* (Docket ID No. EPA-HQ-OAR-2023-0234-0167), the EPA stated that the proposed new data element under 40 CFR 98.236(aa)(3)(ix) would collect similar information to 40 CFR 98.236(aa)(3)(ii). As a result, the EPA proposed to determine that the information collected under 40 CFR 98.236(aa)(3)(ix) would be eligible for confidential treatment.

However, if the EPA finalizes the proposed determination that the industry segment-specific waste emissions thresholds are emission data, then those industry segment-specific waste emissions thresholds would be made publicly available as emission data. Therefore, the EPA is no longer proposing a confidentiality determination for this throughput quantity data element (*i.e.*, the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year) under part 98. The confidentiality status of this data element would be evaluated on a case-by-case basis, in light of any publicly available information and in accordance with the existing regulations in 40 CFR part 2, subpart B, upon receipt of a public request for these data elements.

For Onshore Natural Gas Transmission Compression, the EPA previously decided in 2014 not to make a confidentiality determination that would apply for all facilities for 40 CFR 98.236(aa)(4)(i), the quantity of gas transported through a compressor station. In 79 FR 70352 (November 25, 2014), the EPA explained that we proposed that this data element would not be eligible for confidential treatment because natural gas transmission sector is heavily regulated by FERC and state commissions, resulting in a lack of competition between companies. However, we received comments from this industry sector noting that FERC Order 636 had introduced greater competition to this sector and that some companies charge customers less than the FERC approved rates because of competitive market pressures. The commenters indicated that quantity of gas transported through the compressor station would provide information on the quantity of gas transported by a specific pipeline, which may potentially cause competitive harm to some pipeline companies operating in more competitive market areas. Since the determination would depend on the particular market conditions for each company, the EPA did not make a determination for the data element that would apply for all reporters.[43]

In this rulemaking, the EPA is not proposing to change that previous decision and is still not proposing a confidentiality determination for the quantity of natural gas transported through a compressor station. While the Supreme Court’s 2019 decision in *Argus Leader* altered the review criteria for confidentiality determinations from the Agency’s 2014 decision, the basis provided by commenters to justify the confidential nature of the information is still relevant. For information pertaining to the quantity of gas transported through a compressor station collected under part 99, the EPA will conduct reviews of any claims made under the existing regulations in 40 CFR part 2, subpart B, upon receipt of a public request for this information. Any such reviews will consider the public availability of the same or similar information, including WEC filings, as part of the determination process.

E. Request for Comments on Proposed Category Assignments, Confidentiality Determinations, or Reporting Determinations

This rulemaking provides affected entities that would be subject to part 99, other stakeholders, and the general public an opportunity to provide comment on the proposed amendment to 40 CFR 2.301(d) and the proposed confidentiality determinations for part 99 data, including our proposed categories of emission data and the proposed confidentiality

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[43] Prior to *Argus Leader*, the EPA considered whether the business had satisfactorily shown that disclosure of the information is likely to cause substantial harm to the business’s competitive position when evaluating claims of confidentiality.

determinations for each data element that is not considered emission data. By proposing emission data and confidentiality determinations prior to data reporting through this proposal and rulemaking process, we are providing potentially affected entities an opportunity to submit comments, particularly comments addressing any data elements not entitled to confidential treatment under this proposal, but which companies customarily and actually treat as private. This opportunity to submit comments is intended to provide reporters with the opportunity to substantiate their confidentiality claims that would ordinarily be afforded when the EPA considers claims for confidential treatment of information in case-by-case confidentiality determinations under 40 CFR part 2. In addition, the comment period provides an opportunity to respond to the EPA’s proposed determinations with more information for the Agency to consider prior to finalization. We will evaluate the comments on our proposed determinations, including claims of confidentiality and information substantiating such claims, before finalizing the confidentiality determinations. Please note that this will be reporters’ only opportunity to substantiate a confidentiality claim for data elements included in this proposed rule where information being reported is proposed to be not entitled to confidential treatment. Upon finalizing the confidentiality determinations and reporting determinations of the data elements identified in this proposed rule, the EPA plans to release or withhold these data without further notice in accordance with proposed 40 CFR 2.301(d), which contains special provisions governing the treatment of part 99 data for which confidentiality determinations have been made through rulemaking pursuant to CAA sections 114, 136, and 307(d).

When submitting comments regarding the confidentiality determinations we are proposing in this action, please identify each individual proposed data element on which you are commenting and whether you consider the element to be confidential or do not consider to be “emission data” in your comments. If the data element has been designated as “emission data,” please explain why you do not believe the information meets the definition of “emission data” as defined in 40 CFR 2.301(a)(2)(i). If the data has not been designated as “emission data” and is proposed to not be entitled to confidential treatment, please explain specifically how the data element is commercial or financial information that is both customarily and actually treated as private. Particularly describe the measures currently taken to keep the data confidential and how that information has been customarily treated by your company and/or business sector in the past. This explanation is based on the requirements for confidential treatment set forth in *Argus Leader*.

Members of the public may also discuss how this data element may be different from or similar to data that are already publicly available, including data already collected and published annually by the GHGRP, as applicable. Please submit information identifying any publicly available sources of information containing the specific data elements in question. Data that are already available through other sources would likely be found not to qualify for confidential treatment. In your comments, please identify the manner and location in which each specific data element you identify is publicly available, including a citation. If the data are physically published, such as in a book, industry trade publication, or Federal agency publication, provide the title, volume number (if applicable), author(s), publisher, publication date, and International

Standard Book Number (ISBN) or other identifier. For data published on a website, provide the address of the website, the date you last visited the website and identify the website publisher and content author. Please avoid conclusory and unsubstantiated statements, or general assertions regarding the confidential nature of the information.

In addition to soliciting comment on our proposed confidentiality designations and proposed amendments to 40 CFR 2.301, we are also soliciting comment on the following specific issues relevant to the proposed confidentiality determinations:

"Emission Data" determination. As previously discussed, "emission data" cannot be kept confidential per CAA section 114. The EPA is seeking comment on the part 99 data elements proposed to be considered "emission data." Please specify exactly what part 99 data you think should be considered emission data, describe what part 99 data you think should not be emission data and why (and whether such non-emission data should be considered confidential and why), and clearly explain how the suggested definition of "emission data" would be consistent with the "necessary to determine" clause in 40 CFR 2.301, as well as with the purpose behind the statutory language.

Individual determinations. The EPA is proposing confidentiality determinations by data element for the majority of the data elements in part 99. We are soliciting comment on whether there are data elements proposed to be included in 40 CFR 99.13(a) and (b) for which we should not finalize a confidentiality determination for the data element as not eligible for confidential treatment and instead make no determination for the data element, such that the confidentiality status of this data element would be evaluated on a case-by-case basis, in light of any publicly available information and in accordance with the existing CBI regulations in 40 CFR part 2, subpart B, upon receipt of a public request for these data elements. If respondents believe that EPA should not make a determination for a specific data element, please describe specifics of when a case-by-case determination would be necessary.

Changes to determinations for subpart W throughputs. We request comment on the approach for the subpart W data elements specified in section IV.D. of this preamble. In particular, we request comment on no longer proposing a confidentiality determination for the quantity of residue gas leaving that has been processed by the facility and any gas that passes through the facility to sale without being processed by the facility in the calendar year, in thousand standard cubic feet, reported under proposed 40 CFR 98.236(aa)(3)(ix). We also request comment on the proposal to continue not making a confidentiality determination for the quantity of natural gas transported through a compressor station under 40 CFR 98.236(aa)(4)(i), as well as the criteria that should be used to conduct a case-by-case evaluation of the confidentiality of the data. We also request comment on whether these two data elements are customarily and actually treated as confidential, and if so, what approaches the EPA could use to treat the information as confidential while still making all emission data publicly available, as required by CAA section 114(c).

V. Impacts of the Proposed Amendments

In accordance with the requirements of Executive Order 12866, the EPA projected the emissions reductions, costs, benefits, and transfer payments that may result from this proposed action if finalized as proposed. These results are presented in detail in the *Regulatory Impact*

Analysis of the Proposed Waste Emission Charge (RIA) accompanying this proposal developed in response to Executive Order 12866 and available in the docket to this rulemaking, Docket ID No. EPA-HQ-OAR-2023-0434. This section provides a brief summary of the RIA.

The WEC does not directly require emissions reductions from applicable facilities or emissions sources. However, by imposing a charge on methane emissions that exceed waste emissions thresholds, oil and natural gas facilities subject to the WEC are expected to perform methane mitigation actions and make operational changes where the costs of those changes are less than the WEC payments that could be avoided by reducing methane emissions. In addition, because VOC and HAP emissions are emitted along with methane from oil and natural gas industry activities, reductions in methane emissions as a result of the WEC also result in co-reductions of VOC and HAP emissions.

The RIA accompanying this proposal analyzes emissions changes and economic impacts of the WEC that arise through two pathways: 1) through the application of cost-effective methane mitigation technologies, and 2) through changes in oil and natural gas production and prices resulting from the WEC and associated mitigation responses. The analysis of methane mitigation is based on bottom-up engineering cost and mitigation potential information for a range of methane mitigation technologies. Application of methane mitigation technologies reduce WEC payments for WEC obligated parties by reducing methane emissions compared to a baseline without additional methane mitigation actions. The analysis assumes that methane mitigation is implemented where the engineering control costs are less than the avoided WEC payments for a particular mitigation technology.

Additionally, oil and natural gas firms may change their production and operational decisions in response to the WEC. This potential impact is modeled using a partial equilibrium model of the crude oil and natural gas markets. The total cost of methane mitigation and WEC payments is added as an increase to production costs, resulting in changes in equilibrium production of oil and natural gas and associated emissions. Projected WEC payments are estimated after methane emissions reductions from both methane mitigation and economic impacts are accounted for.

Using emissions reported to subpart W for RY2021 as an illustrative example, Table 1-1 of the RIA shows that the WEC would be imposed on less than 15 percent of national methane emissions from petroleum and natural gas systems. Total methane emissions reported to subpart W are significantly less than national methane emissions from the U.S. Greenhouse Gas Inventory. WEC-applicable facilities are the subset of GHGRP facilities that report at least 25,000 mt CO_2e to subpart W industry segments subject to the WEC. It is also important to note that the WEC would only apply to methane emissions that are above the emissions threshold, not for all emissions from WEC-applicable facilities. The WEC has exemptions related to regulatory compliance, emissions from plugged wells, and unreasonable delay in environmental permitting, although these provisions do not impact the illustrative results in Table 1-1 of the RIA. Finally, emissions subject to WEC accounts for netting of emissions between facilities. Under the proposed WEC, facilities with emissions below their emissions threshold may reduce emissions subject to the WEC at other facilities with emissions above the emissions threshold where those facilities are under common ownership or control.

The benefit-cost analysis contained in the RIA accompanying this rulemaking for the WEC considers the potential benefits and costs of the WEC arising from cost-effective mitigation actions under the WEC as well as the potential transfers from affected operators to the government in payments. Costs include engineering costs for methane mitigation actions and costs resulting from production changes in oil and gas energy markets under this rule. While the EPA expects a range of health and environmental benefits from reductions in methane, VOC, and HAP emissions under the WEC, the monetized benefits of the rule are limited to the estimated climate benefits from projected methane emissions reductions. These benefits are based on the social cost of greenhouse gases (SC-GHG). A screening-level analysis of ozone-related benefits from projected VOC reductions can be found in Appendix A of the RIA. However, these estimates are treated as illustrative and are not included in the quantified benefit-cost comparisons in the RIA.

The EPA estimates that this action will result in cumulative emissions reductions of 960 thousand metric tons of methane over the 2024 to 2035 period. These reductions represent about 33 percent of methane emissions that would be subject to the WEC before accounting for the adoption of cost-effective emission reduction technologies. Virtually all the reduced emissions result from mitigation activities undertaken by industry to reduce WEC payments. Less than one percent of reductions are associated with decreased production activity in the oil and gas sector resulting from the proposed rule. In addition to methane emissions reductions, the WEC is estimated to result in reductions of 140 thousand metric tons of VOC and five thousand metric tons of HAP.

The WEC has important interactions and is designed to work hand-in-hand with the NSPS and EG for the Oil and Natural Gas Sector by accelerating the adoption of cost-effective methane mitigation technologies, including those that would eventually be required under the NSPS or EG. The annual projected emissions reductions, costs, and WEC obligations are significantly affected by these interactions.

The EPA proposed updates to the Oil and Gas NSPS OOOOb/EG OOOOc in 2021, published a supplemental proposal in 2022, and finalized in December 2023. In addition to requirements already in place, these rules include standards for many of the major sources of methane emissions in the oil and natural gas industry. To avoid double counting of benefits and costs, the baseline for this proposal includes reductions resulting from the NSPS OOOOb/EG OOOOc based on information from the 2023 Final RIA. Specifically, that analysis showed deep reductions in methane emissions beginning to take effect in 2028. As facilities implement emission controls required by the NSPS and EG, emissions subject to the WEC decline.

The second interaction between the WEC and NSPS OOOOb/EG OOOOc is the regulatory compliance exemption provision of the WEC. Under this provision, when certain conditions are met with respect to the implementation of the Oil and Gas NSPS OOOOb/EG OOOOc, applicable facilities in compliance with their applicable methane emissions requirements are exempted from the WEC. The analysis in the RIA assumes that the regulatory compliance exemption takes effect in 2027, such that in 2027 and later, facilities in the industry segments subject to requirements under the NSPS OOOOb/EG OOOOc do not owe WEC payments.

Climate benefits associated with this proposed rule are the monetized value of GHG reductions using the SC-GHG, which calculates the avoided climate related damages from reducing GHG emissions. Methane is the principal component of natural gas. As discussed in section I.C.1. of this preamble, methane is also a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change.

This proposed rulemaking is projected to reduce VOC emissions, which are a precursor to ozone. Ozone is not generally emitted directly into the atmosphere but is created when its two primary precursors, VOC and oxides of nitrogen (NO_X), react in the atmosphere in the presence of sunlight. Emissions reductions under the WEC may decrease ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. VOC emissions are also a precursor to $PM_{2.5}$, so VOC reductions may also decrease human exposure to $PM_{2.5}$ and the incidence of $PM_{2.5}$- related health effects.

Available emissions data show that several different HAP are emitted from oil and natural gas operations. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and natural gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4- trimethylpentane.[44] Reductions of HAP emissions under the WEC may reduce exposure to these and other HAP.

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[44] U.S. EPA. The Benefits and Costs of the Clean Air Act from 1990 to 2020. Washington, DC. Retrieved from *https://www.epa.gov/sites/production/files/2015-07/documents/fullreport_rev_a.pdf*.

In section 9.3 of the RIA, the EPA identifies existing potential environmental justice issues for the communities in counties that have emissions sources that are expected to owe the WEC charge before accounting for mitigation actions and thus may be positively affected by emissions changes under the proposal. Compared to the national average, these communities include a higher percentage of individuals who identify as racial and ethnic minorities, have lower average incomes, and have slightly elevated health risks associated with various air emissions. Reductions in VOC and HAP emissions as a result of the WEC are expected to benefit communities in these counties. Because the WEC does not directly require emissions reductions, the EPA has not projected specific locations where emissions reductions might occur. In addition, detailed proximity analysis is infeasible because the emissions affected by the WEC occur at hundreds of thousands of locations.

The total cost of the proposed rule includes the engineering costs for methane mitigation actions implemented by the oil and natural gas industry in order to avoid or reduce WEC obligations. This includes the initial capital costs required to implement and install the specific mitigation technology. In addition, for mitigation technologies with expected lifetimes greater than one-year, annual recurring operations and maintenance costs, which include labor, energy and materials, are also incorporated. Finally, the total mitigation costs also include the avoided cost of natural gas losses.

The social cost of energy market impacts is the loss in consumer and producer surplus value from changes in natural gas market production and prices. The economic impacts analysis uses a partial equilibrium model and estimates that the impact of the gas market is minimal, with the largest impact occurring in the first few years with a price increase of less than 0.1 percent and a quantity reduction of less than 0.1 percent.

Table 5 presents results of the benefit-cost analysis for the proposed WEC. It presents the present value (PV) and equivalent annual value (EAV), estimated using discount rates of 2, 3, and 7 percent, of the changes in quantified benefits, costs, and net benefits relative to the baseline.[45] These values reflect an analytical time horizon of 2024 to 2035, are discounted to 2023, and are presented in 2019 constant dollars. The table includes consideration of the non-monetized benefits associated with the emissions reductions projected under this proposal.

Table 4. Projected Emissions Reductions Under the Proposed Rule, 2024-2035 Total

Pollutant	**Emissions Reductions (2024-2035 Total)**
Methane (thousand metric tons)[a]	960
VOC (thousand metric tons)	140
Hazardous Air Pollutant (thousand short tons)	5

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[45] Monetized climate effects are presented under a 2 percent near-term Ramsey discount rate, consistent with EPA's updated estimates of the SC-GHG. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. OMB finalized an update to Circular A-4 in 2023, in which it recommended the general application of a 2.0 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. Because the SC-GHG estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the discount rate estimated using the average return on capital (7 percent in OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG. See section 6.1 of the RIA for more discussion.

Methane (million metric tons CO_2e)[b]	27

[a] To convert from metric tons to short tons, multiply the short tons by 1.102. Alternatively, to convert from short tons to metric tons, multiply the short tons by 0.907.

[b] Carbon dioxide equivalent (CO_2e). Calculated using a global warming potential of 28.

Table 5. Benefits, Costs, and Net Benefits of the Proposed Rule, 2024 Through 2035 (dollar estimates in millions of 2019 dollars) [a]

	2 Percent Near-Term Ramsey Discount Rate					
	Present Value	**Equivalent Annual Value**	**Present Value**	**Equivalent Annual Value**	**Present Value**	**Equivalent Annual Value**
Climate Benefits[b]	$1,900	$180	$1,900	$180	$1,900	$180
	2 Percent Discount Rate		**3 Percent Discount Rate**		**7 Percent Discount Rate**	
	Present Value	**Equivalent Annual Value**	**Present Value**	**Equivalent Annual Value**	**Present Value**	**Equivalent Annual Value**
Total Social Costs	$390	$37	$380	$38	$340	$43
Cost of Methane Mitigation	$360	$34	$350	$35	$320	$40
Cost of Energy Market Impacts	$30	$3	$29	$3	$26	$3
Net Benefits	$1,500	$140	$1,500	$140	$1,600	$140
Non-Monetized Benefits	Climate and ozone health benefits from reducing 960 thousand metric tons of methane from 2024 to 2035					
	$PM_{2.5}$ and ozone health benefits from reducing 140 thousand metric tons of VOC from 2024 to 2035[c]					
	HAP benefits from reducing 5 thousand metric tons of HAP from 2024 to 2035					
	Visibility benefits					

	Reduced vegetation effects

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

[b] Climate benefits are based on reductions in methane emissions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate. Please see Table 6-5 of the RIA for the full range of monetized climate benefits estimates.

[c] A screening-level analysis of ozone benefits from VOC reductions can be found in Appendix A of the RIA.

WEC payments are transfers and do not affect total net benefits to society as a whole because payments by oil and natural gas operators are offset by receipts by the government. Therefore, from a net-benefit accounting perspective, transfers are considered separately from costs and benefits (and are therefore not included in Table 5). As explained further in section 2.7 of the RIA, the approach taken here is in line with OMB guidance and the approach taken for RIAs for other rules impacting payments to the government, such as the Bureau of Land Management (BLM)’s waste prevention rule.

One of the reasons that transfers are not considered costs is because they represent payments to the U.S. Treasury that do not affect total resources available to society. Payments to the U.S. Treasury can then be used to fund other programs, and the pairing of revenue collection (e.g., the WEC payments) with commensurate expenditures (e.g., financial assistance programs) by the federal government can be designed to be revenue neutral. The Methane Emission Reduction Program created under CAA section 136 includes both collection and expenditure components. In addition to establishing the WEC, another key purpose of CAA section 136 is to encourage the development of innovative technologies in the detection and mitigation of methane emissions. See 168 Cong. Rec. E869 (August 23, 2022) (statement of Rep. Frank Pallone). CAA section 136(a) and (b) provides $1.55 billion to, among other things, help finance the early adoption of emissions reduction methodologies and technologies and to support monitoring of methane emissions. These incentives for methane mitigation and monitoring complement the WEC.

The WEC has the effect of better aligning the economic incentives of oil and natural gas companies with the costs and benefits faced by society from oil and gas activities. In the baseline scenario the environmental damages resulting from methane emissions from the oil and gas sector are a negative externality spread across society as a whole. Under the WEC, this negative externality is internalized, oil and gas companies are required to make WEC payments in proportion to the climate damages of methane emissions subject to the WEC. Alternatively, firms can avoid making WEC payments by mitigating their emissions generating climate benefits associated with the amount of mitigation.

Table 6 provides details of the calculation steps used to estimate projected WEC obligations and climate damages based on projected emission subject to WEC. In order to compare projected WEC payments to climate damages from emissions subject to the WEC, WEC payments are converted from nominal dollars to 2019 constant dollars using a chain-weighted GDP price index from the 2023 Annual Energy Outlook. Projected WEC payments after accounting for methane mitigation and energy market impacts are estimated to be about

$750 million nominal dollars in 2024, and then drop significantly as the regulatory compliance exemption takes effect in 2027.

Table 6. Benefits, Costs, and Net Benefits of the Proposed Rule, 2024 Through 2035 (dollar estimates in millions of 2019 dollars) [a]

Year	Methane Emissions Subject to WEC in Policy Scenario (thousand metric tons)	Charge Specified by Congress (nominal $ per metric ton)	WEC Payments in Policy Scenario (million nominal $)	WEC Payments in Policy Scenario (million 2019$)	SC-CH_4 Values at 2% Discount Rate (2019$ per metric ton)	Climate Damages from Emissions Subject to WEC (million 2019$)[a]
2024	830	$900	$750	$620	$1,900	$1,600
2025	650	$1,200	$770	$630	$2,000	$1,300
2026	430	$1,500	$640	$510	$2,100	$890
2027	9	$1,500	$13	$10	$2,200	$18
2028	9	$1,500	$13	$10	$2,200	$19
2029	9	$1,500	$13	$10	$2,300	$20
2030	9	$1,500	$13	$9	$2,400	$20
2031	9	$1,500	$13	$9	$2,500	$21
2032	9	$1,500	$13	$9	$2,500	$21
2033	8	$1,500	$13	$9	$2,600	$21
2034	8	$1,500	$13	$8	$2,700	$21
2035	8	$1,500	$13	$8	$2,800	$21
Total 2024-2035	2,000	-	$2,300	$1,800	-	$4,000

[a] Climate damages are based on remaining methane emissions subject to WEC after accounting for emissions reductions and are calculated using three different estimates of the social cost of methane (SC-CH_4) (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount

rates). For the presentational purposes of this table, we show the climate benefits associated with the SC-CH_4 at the 2 percent near-term Ramsey discount rate.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a “significant regulatory action” as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket for this rulemaking, Docket ID No. EPA-HQ-OAR-2023-0434. The EPA prepared an analysis of the potential impacts associated with this action. This analysis**,** *Regulatory Impact Analysis of the Proposed Waste Emission Charge***,** is also available in the docket to this rulemaking and is briefly summarized in section V. of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2787.01. You can find a copy of the ICR in the docket for this rule, Docket ID No. EPA-HQ-OAR-2023-0434, and it is briefly summarized here.

The EPA estimates that the proposed rule would result in an increase in burden. The burden associated with the proposed rule is due to reporting and recordkeeping requirements in the proposed rule.

The respondent reporting burden for this collection of information is estimated to be an annual average of 12,799 hours and $1,700,304 over the 3 years covered by this information collection, which includes an annual average of $1,669,752 in labor costs, $0 in operation and maintenance costs, and $30,552 in capital costs. The annual average incremental burden to the EPA for this period is anticipated at 31,200 hours and $5,670,955 ($2023) over the 3 years covered by this information collection, which includes an annual average of $2,004,288 in labor costs and $3,666,667 in non-labor costs.

Respondents/affected entities: Owners and operators of petroleum and natural gas systems that must submit a WEC filing to the EPA to comply with proposed 40 CFR part 99.

Respondent's obligation to respond: The respondent's obligation to respond is mandatory under the authority provided in CAA sections 114 and 136.

Estimated number of respondents: 536.

Frequency of response: Annually.

Total estimated burden: 12,799 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $1.7 million (per year), includes $30,552 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA’s regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency’s need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB’s Office of Information and Regulatory Affairs using the interface at *https://www.reginfo.gov/public/do/PRAMain*. Find this particular information collection by selecting “Currently under Review – Open for Public Comments” or by using the search function. OMB must receive comments no later than **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE *FEDERAL REGISTER*]**. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this proposed action would not have a significant economic impact on a substantial number of small entities under the RFA. The small entities that would be subject to the proposed requirements of this action are small businesses in the petroleum and natural gas industry. Small entities include small businesses, small organizations, and small governmental jurisdictions. The EPA has determined that some small entities are affected because their processes emit methane that must be reported under subpart W and thus may be subject to WEC.

To evaluate whether this proposed rule would have a significant economic impact on a substantial number of small entities, the EPA conducted a small entity analysis that evaluated the costs of the proposed rule on small entities identified in the reporting year (RY) 2021 subpart W dataset. The EPA used reported facility-to-parent company and facility-to-owner or operator data to link facilities to WEC obligated parties. The EPA then reviewed the available RY 2021 data for the WEC obligated parties of subpart W facilities to determine whether the reporters were part of a small entity and whether the annualized costs of the proposal would have a significant impact on a substantial number of small entities. The number of small entities potentially affected by the proposed WEC regulation were estimated based on the information collected for 472 WEC obligated parties. Of these, 439 were identified as small entities. Although the screening analysis suggests that some small entities may have cost-to-revenue ratios that exceed 3 percent (approximately 17 percent), the EPA's evaluation of the impacts to small entities relied on several methodologies involving conservative assumptions. For example, the identification and classification of subpart W parent entities reporting under more than one NAICS code resulted in a designation of "small" based on whether the business information available met the SBA size classification threshold for a single NAICS code. In addition to the conservative assumptions, there were further mitigating factors not included in the screening analysis that would likely significantly reduce compliance costs, and, as a result, cost-to-revenue-ratios. For example, the compliance cost estimate used only the defined WEC cost and did not account for early adoption of mitigation measures that could lower an entity's emissions below the threshold and therefore result in no WEC charge. Details of this analysis are presented in the *Regulatory Impact Analysis of the Proposed Waste Emissions Charge,* available in the docket for this rulemaking. The cumulative effect of the mitigating factors and conservative assumptions used in the screening analysis indicates that, overall, the proposed rule would not likely have a significant impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action contains a federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA has prepared under section 202 of the UMRA a written statement of the benefit-cost analysis, which can be found in Section V of this preamble and in the *Regulatory Impact Analysis of the Proposed Waste Emissions Charge* (RIA), available in the docket for this rulemaking. The proposed action in part implements mandate(s) specifically and explicitly set forth in CAA section 136.

The applicability, magnitude of charge, methane emissions subject to charge, and exemptions from charge for the WEC program are established by CAA section 136(c) through (g). Given that this framework is required by statute, it is not possible for EPA to consider regulatory alternatives that are inconsistent with these elements. As such, to evaluate the benefits and costs of the proposed rule, in the RIA accompanying this rulemaking two scenarios were evaluated: a baseline scenario (*i.e.,* not including the effects of the WEC program) and a policy scenario inclusive of the costs, benefits, and transfers projected under the proposed rule. This action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This proposed rule does not apply to governmental entities unless the government entity owns a facility in the applicable petroleum and gas industry segments and reports more 25,000 mt CO_2e to subpart W of the GHGRP. It would not impose any implementation responsibilities on state, local, or tribal governments and it is not expected to increase the cost of existing regulatory programs managed by those governments. Thus, the impact on governments affected by the proposed rule is expected to be minimal.

However, consistent with the EPA’s policy to promote communications between the EPA and state and local governments, the EPA sought comments from small governments concerning the regulatory requirements that might significantly or uniquely affect them in the development of this proposed rule. Specifically, the EPA previously published a Request for Information (RFI) seeking public comment in a non-regulatory docket to collect responses to a range of questions related to the Methane Emissions Reduction Program, including related to implementation of the WEC (see Docket ID No. EPA-HQ-OAR-2022-0875). The EPA received five comments from government entities related to implementation of the WEC; these comments were considered during the development of the proposed rule. The EPA continues to be interested in the potential impacts of the proposed rule amendments on state, local, or tribal governments and welcomes comments on issues related to such impacts.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. This proposed rule will not apply to governmental entities unless the government entity owns a facility in the applicable petroleum and gas industry segments that and reports more 25,000 mt CO_2e to subpart W of the GHGRP. Therefore, the EPA anticipates relatively few state or local government facilities will be affected. However, consistent with the EPA's policy to promote communications between EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This proposed regulation will apply directly to petroleum and natural gas facilities that may be owned by tribal governments. However, it will generally only have tribal implications where the tribal entity owns a facility in an applicable industry segment that emits GHGs above threshold levels; therefore, relatively few tribal facilities will be affected. Of the subpart W facilities currently reporting to the GHGRP in RY2021, we identified four facilities currently reporting to part 98, subpart W that are owned or partially owned by one tribal parent company. Based on RY2021 data, all four facilities would be WEC applicable facilities, and the WEC applicable emissions (without consideration of exemptions) for the individual facilities would range from less than 0 mt CH_4 for one facility, up to about 3,500 mt CH_4 for the largest facility (which corresponds to a WEC obligation of $3.1 million). Note that one of the facilities is within the onshore natural gas processing sector, and thus, this calculation utilizes proxy data of CBI throughput, which may not reflect the actual facility throughput and resulting WEC applicable emissions. Each of the four facilities has a different owner or operator or combination of owners or operators, so the tribe likely would not be the WEC obligated party for all four facilities. These estimates do not consider any exemptions that might apply for the three facilities with emissions greater than the facility waste emissions threshold.

In addition to tribes that would be directly impacted by the WEC due to owning a facility subject to the charge, the EPA anticipates that tribes could be impacted in cases where facilities subject to the charge are located in Indian country. For example, the EPA reviewed the location of the production wells reported by facilities under the Onshore Petroleum and Natural Gas Production industry segment and found production wells reported under subpart W on lands associated with approximately 20 tribes. Therefore, although the EPA anticipates that at most only one tribe may be designated as a WEC obligated party and has the potential to be subject to the WEC, the EPA has sought opportunities to provide information to tribal governments and representatives during rule development. On November 4, 2022, the EPA published an RFI seeking public comment on a range of questions related to the Methane Emissions Reduction Program, including implementation of the WEC (see Docket ID No. EPA-HQ-OAR-2022-0875). Further, consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA specifically solicits comment on this proposed action from Tribal officials. The EPA will engage in consultation with Tribal officials during the development of this action.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of “covered regulatory action” in section 2-202 of the Executive Order. This proposed action would not establish an environmental standard intended to mitigate health or safety risks and does not focus on information-gathering actions concerned with children’s health. Therefore, this proposed action is not subject to Executive Order 13045. For the same reasons, the EPA’s Policy on Children’s Health also does not apply.

Although this proposed action does not establish an environmental standard applicable to methane emissions or mandate methane emissions reductions, it is expected that the WEC implemented under this proposed action would result in elective methane mitigation actions by applicable facilities in the oil and gas industry in order to reduce, or eliminate, the imposition of charges. As such, the EPA believes that the impacts of this proposed action would result in a reduction in an environmental health or safety risk that has a disproportionate effect on children. Accordingly, the Agency has elected to evaluate the environmental health and welfare effects of climate change on children. Greenhouse gases, including methane, contribute to climate change and are emitted in significant quantities by the oil and gas industry. The EPA believes that the implementation of the WEC in this action, if finalized, would improve children’s health as a result of methane mitigation actions and operational changes taken by oil and gas applicable facilities to avoid the imposition of WEC. The assessment literature cited in the EPA's 2009 Endangerment Findings concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects (74 FR 66524, December 15, 2009). The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience (*e.g.*, the 2016 Climate and Health Assessment).[46] These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses resulting in physical and mental health effects from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with storms and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

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[46] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. *https://dx.doi.org/10.7930/J0R49NQX*.

H. Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not a “significant energy action” because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. To make this determination, we compare the projected change in crude oil and natural gas costs and production to guidance articulated in a January 13, 2021 OMB memorandum “Furthering Compliance with Executive Order 13211, Titled "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use."”[47] With respect to increases in the cost of energy production or distribution, the guidance indicates that a regulatory action produces a significant adverse effect if it is expected to increase costs in excess of one percent. With respect to crude oil production, the guidance indicates that a regulatory action produces a significant adverse effect if it is expected to produce reductions in crude oil supply, in excess of 20 million barrels per year. With respect to natural gas production, the guidance indicates that a regulatory action produces a significant adverse effect if it reduces natural gas production in excess of 40 million thousand cubic feet (mcf) per year.[48] The economic impacts analysis conducted as part of the RIA accompanying this rulemaking estimated a maximum impact on the gas market of a 0.05 percent price increase and a 0.03 percent decrease in production. The

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[47] See *https://www.whitehouse.gov/wp-content/uploads/2021/01/M-21-12.pdf*.

[48] The 2021 E.O. 13211 guidance memo states that the natural gas production decrease that indicates the regulatory action is a significant energy action is 40 mcf per year. Because this is a relatively small amount of natural gas and previous guidance from 2001 indicated a threshold of 25 million Mcf, we assume the 2021 memo was intended to establish 40 million mcf as the indicator of an adverse energy effect. See *https://www.whitehouse.gov/wp-content/uploads/2017/11/2001-M-01-27-Guidance-for-Implementing-E.O.-13211.pdf*.

highest impact year is estimated to be in 2026, with a production decrease of 10.7 million mcf of natural gas. The analysis projected a maximum impact on the oil market of 0.04 percent price increase and a 0.03 percent decrease in production. The highest impact year is estimated to be in 2026, with an estimated production decrease of 1.27 million barrels of oil. These impacts are substantially below the thresholds available in OMB memoranda as measures of a significant adverse effect on the energy supply. Further discussion of this analysis is available in the *Regulatory Impact Analysis of the Proposed Waste Emissions Charge,* available in the docket for this rulemaking.

I. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing our Nation's Commitment to Environmental Justice for All

The EPA believes that the emissions reductions likely to result from this rule will improve health and environmental outcomes for communities facing disproportionate and adverse human health effects from the pollution subject to the waste emissions charge, including environmental justice communities. The EPA proposes, however, to determine that Executive Order 12898 does not apply to this rulemaking because it is a rule that addresses information collection, reporting procedures, and imposition of the waste emission charge directive of CAA section 136. Although the EPA anticipates a reduction in methane and associated co-pollutant emissions from this action, if finalized, these reductions are not the result of emissions standards or mandated reductions.

Although this regulation does not require action that will directly affect human health or environmental conditions, the EPA has identified and addressed environmental justice concerns by electing to conduct a qualitative assessment of the environmental justice outcomes from the proposed action. The EPA believes the human health or environmental conditions that exist prior to this proposed action would result in or have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations, and/or Indigenous peoples. The EPA identified 563 counties where Onshore Petroleum and Natural Gas Production and/or Onshore Petroleum and Natural Gas Gathering and Boosting facilities with emissions that may be above the waste emissions threshold and therefore subject to the WEC operated in 2021. These are the counties where emissions might change due to the WEC. The EPA found that there are generally higher percentages of low income and members of minority groups in these communities who may experience higher than average health risks. The EPA believes that in aggregate the proposed action will result in reduction of methane, hazardous air pollutants, and volatile organic compounds, and, generally, this result will improve environmental justice outcomes.

The information supporting this Executive Order review is contained in the *Regulatory Impact Analysis of the Proposed Waste Emissions Charge*, available in the docket for this rulemaking.

K. Determination under CAA Section 307(d)

Pursuant to CAA section 307(d)(1)(V), the Administrator determines that this proposed action is subject to the provisions of CAA section 307(d). Section 307(d)(1)(V) of the CAA provides that the provisions of CAA section 307(d) apply to "such other actions as the Administrator may determine."

List of Subjects

40 CFR Part 2

Administrative practice and procedure, Confidential business information, Courts, Environmental protection, Freedom of information, Government employees.

40 CFR Part 99

Environmental protection, Greenhouse gases, Natural gas, Petroleum, Reporting and recordkeeping requirements, Penalties.

Dated:

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency proposes to amend title 40, chapter I, of the Code of Federal Regulations as follows:

PART 2—PUBLIC INFORMATION

1. The authority citation for part 2 continues to read as follows:

Authority: 5 U.S.C. 552, 552a, 553; 28 U.S.C. 509, 510, 534; 31 U.S.C. 3717.

Subpart B—Confidentiality of Business Information

2. Amend § 2.301 by revising paragraph (d) to read as follows:

§ 2.301 Special rules governing certain information obtained under the Clean Air Act.

* * * * *

(d) *Data submitted under part 98 or part 99 of this chapter*—(1) Sections 2.201 through 2.215 do not apply to data submitted under part 98 or part 99 of this chapter that EPA has determined, pursuant to sections 114(c) and 307(d) of the Clean Air Act, to be either of the following:

(i) Emission data.

(ii) Data not otherwise entitled to confidential treatment pursuant to section 114(c) of the Clean Air Act.

(2) Except as otherwise provided in this paragraph (d)(2) and paragraph (d)(4) of this section, §§ 2.201 through 2.215 do not apply to data submitted under part 98 or part 99 of this chapter that EPA has determined, pursuant to sections 114(c) and 307(d) of the Clean Air Act, to be entitled to confidential treatment. EPA shall treat that information as confidential in accordance with the provisions of § 2.211, subject to paragraph (d)(4) of this section and § 2.209.

(3) Upon receiving a request under 5 U.S.C. 552 for data submitted under part 98 or part 99 of this chapter that EPA has determined, pursuant to sections 114(c) and 307(d) of the Clean Air Act, to be entitled to confidential treatment, the EPA office shall furnish the requestor a notice that the information has been determined to be entitled to confidential treatment and that the request is therefore denied. The notice shall include or cite to the appropriate EPA determination.

(4) Modification of prior confidentiality determination. A determination made pursuant to sections 114(c) and 307(d) of the Clean Air Act that information submitted under part 98 or part 99 of this chapter is entitled to confidential treatment shall continue in effect unless, subsequent to the confidentiality determination, EPA takes one of the following actions:

(i) EPA determines, pursuant to sections 114(c) and 307(d) of the Clean Air Act, that the information is emission data or data not otherwise entitled to confidential treatment under section 114(c) of the Clean Air Act.

(ii) The Office of General Counsel issues a final determination, based on the criteria in § 2.208, stating that the information is no longer entitled to confidential treatment because of change in the applicable law or newly-discovered or changed facts. Prior to making such final determination, EPA shall afford the business an opportunity to submit comments on pertinent issues in the manner described by §§ 2.204(e) and 2.205(b). If, after consideration of any timely comments submitted by the business, the Office of General Counsel makes a revised final determination that the information is not entitled to confidential treatment under section 114(c) of the Clean Air Act, EPA will notify the business in accordance with the procedures described in § 2.205(f)(2).

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3. Add part 99 to read as follows:

PART 99—WASTE EMISSIONS CHARGE

Sec.

Subpart A—General Provisions

Subpart B—Determining Waste Emissions Charge

Subpart C—Unreasonable Delay Exemption

Subpart D—Regulatory Compliance Exemption

Subpart E—Exemption for Permanently Shut-in and Plugged Wells

Authority: 42 U.S.C. 7401–7671q; 31 U.S.C. 3717.

Subpart A—General Provisions

§ 99.1 Purpose and scope.

(a) This part establishes requirements for owners and operators of certain petroleum and natural gas systems facilities to make filings and be assessed waste emission charges as required by section 136 of the Clean Air Act.

(b) Owners and operators of facilities that are subject to this part must follow the requirements of this subpart and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the applicable subpart shall take precedence.

§ 99.2 Definitions.

All terms used in this part shall have the same meaning given in the Clean Air Act, unless as defined in this section. Terms defined here only apply within the context of this rulemaking.

Act means the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.*

Affected facility means, for the purposes of the regulatory compliance exemption of this part, affected facilities, as defined in part 60, subpart A of this chapter, that are subject to methane emissions requirements pursuant to part 60 of this chapter.

Applicable facility means a facility within one or more of the following industry segments, as those industry segment terms are defined in § 98.230 of this chapter. In the case where operations from two or more industry segments are co-located at the same part 98 reporting facility, operations for all co-located segments constitute a single *applicable facility* under this part:

(1) Offshore petroleum and natural gas production.

(2) Onshore petroleum and natural gas production.

(3) Onshore natural gas processing.

(4) Onshore natural gas transmission compression.

(5) Underground natural gas storage.

(6) Liquefied natural gas storage.

(7) Liquefied natural gas import and export equipment.

(8) Onshore petroleum and natural gas gathering and boosting.

(9) Onshore natural gas transmission pipeline.

Carbon dioxide equivalent or CO_2e means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas and is calculated using Equation A-1 in § 98.2(b) of this chapter.

Designated facility means, for purposes of the regulatory compliance exemption of this part, designated facilities, as defined in § 60.21a(b) of this chapter, subject to methane emissions requirements pursuant to a state, Tribal, or Federal plan implementing part 60 of this chapter.

e-GGRT ID number means the identification number assigned to a facility by the EPA's electronic Greenhouse Gas Reporting Tool for submission of the facility's part 98 report.

Facility applicable emissions means the annual methane emissions, as calculated in § 99.21, associated with a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the WEC applicable facility prior to consideration of any applicable exemptions.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

Global warming potential or GWP means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas (*i.e.,* CO_2). GWPs for each greenhouse gas are provided in Table A-1 of part 98, subpart A of this chapter.

Greenhouse gas or GHG means the air pollutants carbon dioxide (CO_2), hydrofluorocarbons (HFCs), methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

Nonproduction sector means facilities in the onshore natural gas processing, the liquefied natural gas storage, the liquefied natural gas import and export equipment, and the onshore petroleum and natural gas gathering and boosting industry segments as those industry segments are defined in § 98.230 of this chapter.

Onshore natural gas transmission pipeline owner or operator means, for interstate pipelines, the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, or, for intrastate pipelines, the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act, or for pipelines that fall under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994), the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224. If an intrastate pipeline is not subject to section 311 of the Natural Gas Policy Act (NGPA), the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates a facility in the onshore petroleum and/or natural gas production industry segment (as that industry segment is defined in § 98.230(a)(2) of this chapter). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operator means, except as otherwise defined in this section, any person who operates or supervises a facility.

Owner means, except as otherwise defined in this section, any person who has legal or equitable title to, has a leasehold interest in, or control of an applicable facility, except a person whose legal or equitable title to or leasehold interest in the facility arises solely because the person is a limited partner in a partnership that has legal or equitable title to, has a leasehold interest in, or control of the facility shall not be considered an "owner" of the facility.

Part 98 report means the annual report required under part 98 of this chapter for owners and operators of certain facilities under the Petroleum and Natural Gas Systems source category.

Petroleum means oil removed from the earth and the oil derived from tar sands and shale.

Production sector means facilities in the offshore petroleum and natural gas production and the onshore petroleum and natural gas production industry segments as those industry segments are defined in § 98.230 of this chapter.

Reporting year means the calendar year during which data are required to be collected for purposes of the annual WEC filing. For example, reporting year 2024 is January 1, 2024 through December 31, 2024, and the annual WEC filing for reporting year 2024 is submitted to EPA by March 31, 2025.

Standard temperature and pressure means 60° F and 14.7 psia.

Transmission sector means facilities in the onshore natural gas transmission compression, the underground natural gas storage, and the onshore transmission pipeline industry segments as those industry segments are defined in § 98.230 of this chapter.

Waste emissions threshold means the metric tons of methane emissions calculated by multiplying WEC applicable facility throughput by the industry segment-specific methane intensity thresholds established in CAA 136(f) and the density of methane (0.0192 metric ton per thousand standard cubic feet).

WEC means waste emissions charge, the charge established in CAA 136(c) on methane emissions that exceed certain thresholds.

WEC applicable emissions means the annual methane emissions, as calculated in § 99.21, associated with a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the WEC applicable facility after consideration of any applicable exemptions.

WEC applicable facility means an applicable facility, as defined in this section, for which the owner or operator of the part 98 reporting facility reports GHG emissions under part 98, subpart W of this chapter of more than 25,000 metric tons CO_2e.

WEC filing means the report and payment of applicable WEC obligation required to be submitted by a WEC obligated party under the requirements of this chapter. The WEC filing contains information regarding the WEC obligated party and WEC applicable facilities for the previous reporting year. For example, the WEC filing due on March 31, 2025 contains information regarding reporting year 2024, which is January 1, 2024 through December 31, 2024.

WEC obligated party means the owner or operator as defined in this section for the applicable industry segment as of December 31 of the reporting year. In cases where a WEC applicable facility has more than one owner or operator, the WEC obligated party shall be a person or entity selected by an agreement binding on each of the owners and operators involved in the transaction, following the provisions of § 99.4(b).

WEC obligation means the WEC charge amount resulting from the calculations in § 99.23.

You means a WEC obligated party subject to this part 99.

§ 99.3 Who must file?

WEC obligated parties, as defined in § 99.2, are required to submit a WEC filing and remit applicable WEC obligations and charges.

§ 99.4 How do I authorize and what are the responsibilities of the designated representative?

Each WEC obligated party must follow the procedures in paragraphs (a) through (l) of this section, as applicable, to identify a WEC obligated party designated representative. In cases where a WEC applicable facility has more than one owner or operator, the WEC obligated party shall be a person or entity selected by an agreement binding on each of the owners and operators involved in the transaction, following the provisions of paragraph (b) of this section. Failure to select a WEC obligated party for each WEC applicable facility with multiple owners or operators following the procedures of paragraph (b) of this section is considered a violation of this part for each owner and operator (as defined in § 99.2 of this part) for the applicable industry segment of the associated WEC applicable facility.

(a) *General*. Except as provided under paragraph (f) of this section, each WEC obligated party that is subject to this part shall have one designated representative, who shall be responsible for certifying, signing, and submitting WEC filings or other submissions to the Administrator under this part.

(b) *Authorization of a designated representative*. The designated representative of each WEC obligated party shall be an individual selected by an agreement binding on the owner and operator of such entity and shall act in accordance with the certification statement in paragraph (i)(3)(iv) of this section. Failure of a WEC obligated party to authorize a designated representative following the procedures of this section is considered a violation of this part.

(c) *Responsibility of the designated representative*. Upon receipt by the Administrator of a complete certificate of representation under this section for the WEC obligated party, the designated representative identified in such certificate of representation shall represent and, by his or her representations, actions, inactions, or submissions, legally bind the owner and operator of such an entity in all matters pertaining to this part, notwithstanding any agreement between the designated representative and said owner and operator. The owner and operator shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) *Timing*. No WEC filing or other submissions under this part for a WEC obligated party will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the WEC obligated party. Such certificate of representation shall be submitted at least 60 days before the deadline for submission of the WEC obligated party’s WEC filing under § 99.5.

(e) *Certification of the WEC filing*. Each WEC filing and any other submission under this part for a WEC obligated party shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the WEC obligated party in accordance with this section and § 3.10 of this chapter.

(1) Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owner and operator of the WEC obligated party, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) The Administrator will accept a WEC filing or other submission for a WEC obligated party under this part only if the submission is certified, signed, and submitted in accordance with this section.

(f) *Alternate designated representative*. A certificate of representation under this section for the WEC obligated party may designate one alternate designated representative, who shall be an individual selected by an agreement binding on the owner and operator, and may act on behalf of the WEC obligated party designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) Upon receipt by the Administrator of a complete certificate of representation under this section for a WEC obligated party identifying an alternate designated representative, the following apply.

(i) The alternate WEC obligated party designated representative may act on behalf of the WEC obligated party designated representative.

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the WEC obligated party designated representative.

(2) Except in this section, whenever the term “designated representative” is used in this part, the term shall be construed to include the designated representative or any alternate designated representative.

(g) *Changing a designated representative or alternate designated representative*. The designated representative or alternate designated representative identified in a complete certificate of representation under this section for a WEC obligated party received by the Administrator may be changed at any time upon receipt by the Administrator of another later signed, complete certificate of representation under this section for the WEC obligated party. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative or the previous alternate designated representative of the WEC obligated party before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owner and operator of the WEC obligated party.

(h) *Changes in the WEC obligated party*. Within 90 days after any change in the WEC obligated party, the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section to reflect the change.

(i) *Certificate of representation*. A certificate of representation shall be complete if it includes the following elements in a format prescribed by the Administrator in accordance with this section:

(1) Identification of the WEC obligated party for which the certificate of representation is submitted.

(2) The name, organization name (company affiliation-employer), address, e-mail address, telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) The following certification statements by the designated representative and any alternate designated representative:

(i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owner and operator of the entity.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 99 on behalf of the owner and operator of the entity and that such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”

(iii) “I certify that the owner and operator of the entity, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the entity.”

(iv) “If there are multiple owners and operators of the entity, I certify that I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the entity.”

(4) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) *Documents of agreement*. Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) *Binding nature of the certificate of representation*. Once a complete certificate of representation under this section for a WEC obligated party has been received, the Administrator will rely on the certificate of representation unless and until a later signed, complete certificate of representation under this section for the facility is received by the Administrator.

(l) Objections concerning a designated representative.

(1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the

designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

§ 99.5 When must I file and remit the applicable WEC obligation?

Each WEC obligated party must submit their WEC filing including the information specified in § 99.7 and remit applicable WEC obligation no later than March 31 of the year following the reporting year. All filing revisions must be received according to the schedule in § 99.7(e) to be considered for revisions to WEC obligations. If the submission date falls on a weekend or a federal holiday, the submission date shall be extended to the next business day.

§ 99.6 How do I file?

Each WEC filing, certificate of representation, and remittance of applicable WEC fees for the WEC obligated party must be submitted electronically in accordance with the requirements of this part and in a format specified by the Administrator.

§ 99.7 What are the general reporting, recordkeeping, and verification requirements of this part?

The WEC obligated party that is subject to the requirements of this part must submit a WEC filing to the Administrator as specified in this section.

(a) *Schedule*. The WEC filing must be submitted in accordance with § 99.5.

(b) *Content of the WEC filing*. For each WEC obligated party, report the information in paragraphs (b)(1)(i) through (v) of this section. For each WEC applicable facility under common ownership or control of the WEC obligated party, report the information in paragraphs (b)(2)(i) through (vii) of this section. The WEC filing must also include payment of applicable WEC obligation, as specified in paragraph (b)(3) of this section.

(1) Reporting requirements at the WEC obligated party level.

(i) The company name.

(ii) The United States address for the company.

(iii) The name, address, e-mail address, and phone number for the designated representative for the WEC obligated party.

(iv) The list of e-GGRT ID number(s) under which the WEC applicable facilities comprising the WEC obligated party as of December 31 of the reporting year report under part 98, subpart W of this chapter.

(v) The net WEC emissions, as calculated pursuant to § 99.22, and WEC obligation, as calculated pursuant to § 99.23, for the WEC obligated party.

(2) Reporting requirements for each WEC applicable facility comprising the WEC obligated party.

(i) The e-GGRT ID under which the WEC applicable facility emissions are reported under part 98, subpart W of this chapter.

(ii) The industry segment(s) for the WEC applicable facility.

(iii) For WEC applicable facilities in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment as defined in § 99.2, if conditions specified in § 99.30 regarding emissions from delays in permitting are met, provide information as specified in § 99.31.

(iv) If the conditions specified in § 99.40 are met regarding the regulatory compliance exemption, report whether the WEC applicable facility contains any affected facilities under part 60 of this chapter or any designated facilities under an applicable approved state, Tribal, Federal plan in part 62 of this chapter. If so, provide the information specified in § 99.41, as applicable.

(v) For WEC applicable facilities in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment as defined in § 99.2, if conditions specified in § 99.50 regarding emissions from permanently shut-in and plugged wells are met, you must report the information specified in § 99.51.

(vi) The facility waste emissions threshold as calculated pursuant to § 99.20, and, if there is more than one applicable industry segment within the WEC applicable facility, each industry segment waste emissions threshold for each applicable industry segment within the applicable facility, as calculated pursuant to § 99.20,

(vii) The facility applicable emissions, as calculated pursuant to § 99.21 and the WEC applicable emissions, as calculated pursuant to § 99.21.

(3) Payment of applicable WEC obligation, submitted in accordance with § 99.9.

(c) *Verification of the WEC filing*. To verify the completeness and accuracy of WEC filing, the EPA will consider the verification status of part 98 reports, and may review the certification statements described in § 99.4 and any other credible evidence, in conjunction with a comprehensive review of the WEC filing, including attachments. The EPA may conduct audits of selected WEC obligated parties and associated WEC applicable facilities. During such audits, the records generated under this part must be made available to the EPA. The on-site audits may be conducted by private auditors contracted by the EPA or by Federal, State or local personnel, as appropriate, and may be required to be arranged by and conducted at the expense of the WEC obligated party. Nothing in this section prohibits the EPA from using additional information, including reports, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, orFederal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, to verify the completeness and accuracy of the filings.

(d) *Recordkeeping*. Retain all required records for at least 5 years from the date of submission of the WEC filing for the reporting year in which the record was generated. The records shall be kept in an electronic or hard-copy format (as appropriate) and recorded in a form that is suitable for expeditious inspection and review. Upon request by the Administrator, the records required under this section must be made available to EPA. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records:

(1) All information required to be retained by part 98, subparts A and W of this chapter.

(2) Any other information not included in a part 98 report used to complete the WEC filing.

(3) All information required to be submitted as part of the WEC filing.

(e) *Annual WEC filing revisions*. Except as specified in paragraph (e)(2) of this section, the provisions of this paragraph (e) apply until November 1 of the year following the reporting year, or for a given reporting year after the November 1 deadline if the resubmission is related to the resolution of unverified data process specified at § 99.8.

(1) The WEC obligated party shall submit a revised WEC filing within 45 days of discovering that a previously submitted WEC filing contains one or more substantive errors. The revised WEC filing must correct all substantive errors. If the resubmission is due to a correction in a part 98 report resubmitted by a WEC applicable facility, the WEC obligated party must report the number of corrections made in the part 98 report(s) and a description of how the changes impact the assessment of the WEC obligation.

(2) The revisions for substantive errors as described in paragraph (e)(2)(i) and (ii) are not subject to the November 1 deadline and must be submitted according the schedule therein.

(i) Revised filings for purposes of the regulatory compliance exemption must be submitted as follows:

(A) Revised filings to submit a CAA section 111(b) or (d) compliance report which covers the remaining portion of a WEC filing year, which were not available at the time of the WEC filing, must be submitted on or before the date that the compliance report covering the remainder of the year is due under the applicable requirements of CAA section 111(b) or (d), as applicable.

(B) Revised filings to submit findings by the WEC obligated party that one or more deviations or violations discovered after the WEC filing must be submitted within 45 days of the discovery.

(ii) The Administrator may notify the WEC obligated party in writing that a WEC filing previously submitted by the owner or operator contains one or more substantive errors. Such notification will identify each such substantive error. The WEC obligated party shall, within 45 days of receipt of the notification, either resubmit the WEC filing that, for each identified substantive error, corrects the identified substantive error (in accordance with the applicable requirements of this part) or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error. The EPA reserves to right to revise WEC obligations for a given reporting year after the November 1 final resubmission deadline if data errors are discovered by EPA at a later date.

(3) A substantive error is an error that impacts the Administrator’s ability to accurately calculate a WEC obligated party’s WEC obligation, which may include, but is not limited to, the list of WEC applicable facilities associated with a WEC obligated party, the emissions or throughput reported in the WEC applicable facility part 98 report(s), emissions associated with exemptions, and supporting information for each exemption to demonstrate its validity.

(4) Notwithstanding paragraphs (e)(1) and (2) of this section, upon request the Administrator may provide an extension of the 45-day period for submission of a revised report or information under paragraphs (e)(1) and (2) of this section if adequate justification is provided by the WEC obligated party. The Administrator may provide an extension of up to 30 days provided that the request is received by email to an address prescribed by the Administrator prior to the expiration of the 45-day period and that the request demonstrates that it is not practicable to submit a revised report or information under paragraphs (e)(1) and (2) of this section within 45 days.

(5) The WEC obligated party shall retain documentation for 5 years to support any revision made to a WEC filing.

(6) If a facility changes ownership such that there is a change to the WEC obligated party, the entity that was the WEC obligated party at the time of the original filing for a reporting year remains responsible for any revisions to WEC filings for that reporting year.

(f) *Designation of unverified filings and reports*. Following the verification process discussed in § 98.3(h) of this chapter for part 98 reports and paragraph (c) of this section for WEC filings, the EPA shall designate:

(1) The annual part 98 report associated with each WEC applicable facility as either verified or unverified. An unverified report is one in which the EPA has provided notification under § 98.3(h)(2) of this chapter and the owner or operator of the WEC applicable facility has failed to revise and resubmit the report and resolve the error or provide justification to the

satisfaction of the EPA that the identified error is not a substantive error (in accordance with the applicable requirements of § 98.3(h)(3) of this chapter).

(2) The annual WEC filing from each WEC obligated party submitted pursuant to § 99.7 as either verified or unverified. An unverified filing is one in which the EPA has provided notification under § 99.7(e)(2) and the WEC obligated party designated representative has failed to resubmit the report and for each identified substantive error correct the identified substantive error (in accordance with the applicable requirements of paragraph (e)(3) of this section) or provide information demonstrating that the submitted report does not contain the identified substantive error or that the identified error is not a substantive error. The determination of verification status of a part 98 report under paragraph (f)(1) of this section will be taken into consideration in the determination of the verification status of a WEC filing.

§ 99.8 What are the general provisions for assessment of the WEC obligation?

(a) *Assessment of the WEC obligation*. WEC obligation assessments shall be made pursuant to § 99.23 on the basis of information submitted by the date specified in § 99.5 and following the submittal requirements of § 99.6.

(b) *Assessment of the WEC obligation for unverified filings*. If a WEC filing is unverified but the EPA is able to correct the error(s) based on reported data, the EPA will recalculate the WEC using available information and provide an invoice or refund to the WEC obligated party within 60 days of determining a WEC filing to be unverified. If the WEC obligated party resubmits a WEC filing within that timeframe, the EPA will either verify the resubmission, or take the resubmission into account when calculating the WEC.

(c) *Third-party audits for unverified reports*. If the EPA is unable to calculate the WEC with available information, the EPA may require the WEC obligated party to undergo a third party audit. The EPA may require the WEC obligated party to fund and arrange the third-party audit. The third-party auditor must review records kept by the WEC obligated party, quantify the WEC with available information, and the updated WEC calculations and supporting data must be submitted to the EPA. The EPA will then take that information into consideration and calculate the WEC and provide an invoice or refund to the WEC obligated party.

(1) *Third party reviews*. An independent third-party audit of the information provided shall be based on a review of the relevant documents and shall identify each item required by the WEC filing, describe how the independent third-party evaluated the accuracy of the information provided, state whether the independent third-party agrees with the information provided, and identify any exceptions between the independent third-party's findings and the information provided.

(i) Audits required under this section must be conducted by a certified independent third-party. The auditor must have professional work experience in the petroleum engineering field or related to oil and gas production, gathering, processing, transmission or storage.

(ii) To be considered an independent third-party, the independent third party shall not be operated by the WEC obligated party and the independent third party shall be free from any interest in the WEC obligated party’s business.

(iii) The independent third-party shall submit all records pertaining to the audit required under this section, including information supporting all of the requirements of § 99.8(c)(1) to the WEC obligated party.

(iv) The independent third-party must provide to the WEC obligated party documentation of qualifications of professional work experience in the petroleum engineering field or related to oil and gas production, gathering, processing, transmission or storage.

(2) *Reporting and recordkeeping requirements for WEC obligated parties following third party audits*.

(i) The WEC obligated party shall provide to EPA the results of the third-party audit, including the WEC obligation amount and all supporting documentation information that is included in reporting requirements under §§ 99.7, and 99.31, 99.41, and 99.51, as applicable.

(ii) The WEC obligated party shall provide to EPA documentation of qualifications of the third-party auditor.

(iii) The WEC obligated party shall retain all records pertaining to the audit required under this section for a period of 5 years from the date of creation and shall deliver such records to the Administrator upon request.

(d) *Resubmittal of filings and reports for the current or prior reporting year*. If resubmittal of a previously submitted part 98 report and/or WEC filing, submitted as specified in §99.7(e), results in a change to the WEC obligation determined for a WEC obligated party for the reporting yearthe following process shall apply:

(1) If the WEC obligation based upon the resubmitted report or filing for the reporting year is less than the WEC obligation previously remitted by the WEC obligated party, the Administrator shall authorize a refund to the WEC obligated party equal to the difference in WEC obligation.

(2) If the WEC obligation based upon the resubmitted report or filing for the reporting year is greater than the WEC obligation previously remitted by the WEC obligated party, the Administrator shall issue an invoice to the WEC obligated party containing a charge in the amount determined using Equation A-1 of this section. Interest shall not be assessed for a change in WEC obligation resulting from the timely submittal of a regulatory report in accordance with § 99.41(c).

$$WEC_r = \Delta WEC \times \left(1 + \frac{i_{CVFR}}{365}\right)^t \qquad \text{(Eq. A-1)}$$

Where:

WEC_r = The charge obligation of the WEC obligated party to be resubmitted for the difference in WEC obligation, including any applicable interest, in dollars.

ΔWEC = The difference in WEC obligation, calculated as the amount remitted upon the original submittal specified in § 99.5 subtracted from the quantity of WEC obligation determined based upon the resubmitted report or filing, in dollars.

i_{CVFR} = The Treasury Current Value of Funds Rate as specified in § 99.10(b).

t = The number of days after the deadline specified in § 99.5 for remittance of WEC obligation for the reporting year that the resubmitted WEC filing or part 99 report was received by the Administrator, in days. For example, if a reporting year 2024 part 99 report is resubmitted on April 28, 2025, “t” is equal to 28 days. If a reporting year 2024 part 99 report is resubmitted on April 28, 2026, "t" is equal to 393 days.

365 = Conversion factor from years to days.

§ 99.9 How are payments required by this part made?

(a) The WEC obligation owed for each reporting year must be paid by the WEC obligated party as part of the annual WEC filling, as required by § 99.7(b), and is considered due at the date specified in § 99.5.

(b) Other than the WEC obligation specified in paragraph (a) of this section, all other charges required by this part, including adjusted WEC obligations, interest fees, and penalties, shall be paid by the WEC obligated party in response to an electronic invoice or bill by the specified due date, or within 30 days of the date of the invoice or bill if a due date is not provided.

(c) All WEC obligations, interest fees, and penalties required by this subpart shall be paid to the Department of the Treasury by the WEC obligated party electronically in U.S. dollars, using an online electronic payment service specified by the Administrator.

§ 99.10 What fees apply to delinquent payments?

(a) *Delinquency*. WEC obligated party accounts are delinquent if the WEC obligation payment is not submitted in full by the date required by § 99.5. WEC obligated party accounts are also delinquent if the accounts remain unpaid after the due date specified in the invoice or other notice of the WEC amount owed.

(b) *Interest fee*. In accordance with 31 U.S.C. 3717(a), delinquent WEC obligated party accounts shall be charged a minimum annual rate of interest equal to the average investment rate for Treasury tax and loan accounts (Current Value of Funds Rate or CVFR) most recently published and in effect by the Secretary of the Treasury.

(c) *Non-payment penalty*. In accordance with 31 U.S.C. 3717(e), WEC obligated party accounts that are more than 90 days past due shall be charged an additional penalty of 6% per year assessed on any part of the debt that is past due for more than 90 days.

(d) *Penalty for non-submittal*. In accordance with 42 U.S.C. 7413(d)(1), a WEC obligated party that fails to submit an annual WEC filing by the date specified in § 99.5 may be charged an administrative penalty. The penalty assessment shall be a daily assessment per day that the WEC filing is not submitted, assessed up to the value specified in Table 1 of § 19.4, as amended, of this chapter. The assessment of penalty shall begin on the date that the WEC filing was considered past due per § 99.5 and continue until such time that the WEC filing is submitted by the WEC obligated party’s designated representative.

§ 99.11 What are the compliance and enforcement provisions of this part?

Any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. 7414) and section 136 (42 U.S.C. 7436). A violation would include, but is not limited to, failure to submit a WEC filing, failure to collect data needed to calculate the WEC charge (including any data relevant to determining the applicability of any exemptions), failure to select a WEC obligated party, failure to retain records needed to verify the amount of WEC charge, providing false information in a WEC filing, and failure to remit

WEC payment. Each day of a violation would constitute a separate violation. Each day of each violation constitutes a separate violation. Any penalty assessed shall be in addition to any WEC obligation due under this part and any fees applicable to delinquent payments due under § 99.10.

§ 99.12 What addresses apply for this part?

All requests, notifications, and communications to the Administrator pursuant to this part must be submitted electronically and in a format as specified by the Administrator.

§ 99.13 What are the confidentiality determinations and related procedures for this part?

This section characterizes various categories of information for purposes of making confidentiality determinations, as follows:

(a) This paragraph (a) applies the definition of “Emission data” in 40 CFR 2.301(a) for information reported under this part. “Emission data” cannot be treated as confidential business information and shall be available to be disclosed to the public. The following categories of information qualify as emission data:

(1) Methane emission information, including the net WEC emissions, waste emissions thresholds, WEC applicable emissions, and the quantity of methane emissions to be exempted due to unreasonable delay and wells that were permanently shut-in and abandoned.

(2) Calculation methodology, including the method used to determine the quantity of methane emissions to be exempted due to an unreasonable permitting delay and the method used to quantify emissions exempted from permanently shut-in and plugged wells.

(3) Facility and unit identifier information, including WEC obligated party company name and address, the name and contact information for the designated representative of WEC

obligated party, signed and dated certification statements of the accuracy and completeness of the report, facility identifiers (*e.g.*, e-GGRT ID number), industry segment, well-pad and/or well identifiers, and emission source-specific methane mitigation activities impacted by an unreasonable permitting delay.

(b) The following types of information are not eligible for confidential treatment:

(1) The WEC obligation, as calculated pursuant to § 99.23.

(2) Compliance information, including information regarding applicable emissions standards or other relevant standards of performance or requirements, information in construction or operating permits, and information submitted to document compliance with an emissions standard or a standard of performance, such as a periodic report, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, orFederal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, (excluding any information redacted from the report and claimed as confidential).

(3) Published information that is publicly available, including information that is made available through publication of annual reports submitted under part 98 of this chapter, on company or other websites, or otherwise made publicly available.

(c) If you submit information that is not described in paragraphs (a) and (b) of this section, you may claim the information as confidential and the information is subject to the process for confidentiality determinations in 40 CFR part 2 as described in §§ 2.201 through 2.208. We may require you to provide us with information to substantiate your claims. If claimed, we may consider this substantiating information to be confidential to the same degree as the information for which you are requesting confidential treatment. We will make our determination based on your statements to us, the supporting information you send us, and any other available information. However, we may determine that your information is not subject to confidential treatment consistent with 40 CFR part 2 and 5 U.S.C. 552(b)(4).

(d) Submitted applications and reports typically rely on software or templates to identify specific categories of information. If you submit information in a comment field designated for users to add general information, we will respond to requests for disclosing that information consistent with paragraphs (a) through (c) of this section.

Subpart B—Determining Waste Emissions Charge

§ 99.20 How will the waste emissions threshold for each WEC applicable facility be determined?

The methane waste emissions threshold for each applicable industry segment within a WEC applicable facility for the reporting year will be calculated as described in paragraphs (a) through (d) of this section, as applicable. The methane waste emissions threshold for each WEC applicable facility will be determined as described in paragraph (e) of this section.

(a) For each offshore petroleum and natural gas production industry segment or onshore petroleum and natural gas production industry segment that sends natural gas to sale at a WEC applicable facility, the facility waste emissions threshold will be calculated using Equation B-1 of this section.

$$TH_{is,Prod} = 0.002 \times \rho_{CH_4} \times Q_{ng,Prod} \qquad \text{(Eq. B-1)}$$

Where:

$TH_{is,Prod}$ = The methane waste emissions threshold for the industry segment at a WEC applicable facility for the reporting year in the production sector that has natural gas sent to sale, metric tons (mt) CH_4.

0.002 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for methane emissions for applicable facilities with natural gas sales in the production sector, thousand standard cubic feet (Mscf) CH_4 per Mscf of natural gas sent to sale.

ρ_{CH4} = Density of methane = 0.0192 kilograms per standard cubic foot (kg/scf) = 0.0192 metric tons per thousand standard cubic feet (mt/Mscf).

$Q_{ng,Prod}$ = The total quantity of natural gas that is sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to part 98, subpart W of this chapter. For onshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(1)(i)(B) of this chapter, in Mscf. For offshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(2)(i) of this chapter, in Mscf.

(b) For each offshore petroleum and natural gas production industry segment or the onshore petroleum and natural gas production industry segment that has no natural gas sent to sale at a WEC applicable facility, the facility waste emissions threshold will be calculated using Equation B-2 of this section.

$$TH_{is,Prod} = 10 \times Q_{o,Prod} \times 10^{-6} \qquad \text{(Eq. B-2)}$$

Where:

$TH_{is,Prod}$ = The annual methane waste emissions threshold for the industry segment at a WEC applicable facility in the production sector that has no natural gas sent to sale, mt CH_4.

10 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for applicable facilities with no natural gas sales in the production sector, mt CH_4 per million barrels oil sent to sale.

$Q_{o,Prod}$ = The total quantity of crude oil that is sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to part 98, subpart W of this chapter. For onshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(1)(i)(C) of this chapter, in barrels. For offshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(2)(ii) of this chapter, in barrels.

10^{-6} = Conversion from barrels to million barrels.

(c) For each onshore natural gas processing industry segment, liquefied natural gas storage industry segment, the liquefied natural gas import and export equipment industry segment, or the onshore petroleum and natural gas gathering and boosting industry segment at a WEC applicable facility, the facility waste emissions threshold will be calculated using Equation B-3 of this section.

$$TH_{is,NonProd} = 0.0005 \times \rho_{CH_4} \times Q_{ng,NonProd} \qquad \text{(Eq. B-3)}$$

Where:

$TH_{is,NonProd}$ = The annual methane waste emissions threshold for the industry segment at a WEC applicable facility in the nonproduction sector, mt CH_4.

0.0005 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for applicable facilities in the nonproduction sector, Mscf CH_4 per Mscf of natural gas sent to sale from or through the facility.

ρ_{CH4} = Density of methane = 0.0192 kg/scf = 0.0192 mt/Mscf.

$Q_{ng,NonProd}$ = The total quantity of natural gas that is sent to sale from or through the industry segment at a WEC applicable facility in the reporting year as reported pursuant to part 98, subpart W of this chapter. For RY 2024 for onshore natural gas processing, you must use the quantity reported pursuant to § 98.236(aa)(3)(ii) of this chapter, in Mscf and for RY 2025 and later, you must use the quantity reported pursuant to proposed § 98.236(aa)(3)(ix) of this chapter, in Mscf. For LNG import and export, you must use sum of the quantities reported pursuant to § 98.236(aa)(6) and (7) of this chapter, in Mscf. For LNG storage, you must use the quantity reported pursuant to § 98.236(aa)(8)(ii) of this chapter, in Mscf. For onshore petroleum and natural gas gathering and boosting, you must use the quantity reported pursuant to § 98.236(aa)(10)(ii) of this chapter, in Mscf .

(d) For each onshore natural gas transmission compression industry segment, underground natural gas storage industry segment, or onshore natural gas transmission pipeline industry segment at a WEC applicable facility, the facility waste emissions threshold will be calculated using Equation B-4 of this section.

$$TH_{is,Tran} = 0.0011 \times \rho_{CH_4} \times Q_{ng,Tran} \qquad \text{(Eq. B-4)}$$

Where:

$TH_{is,Tran}$ = The annual methane waste emissions threshold for the industry segment at a WEC applicable facility in the transmission sector, mt CH_4.

0.0005 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for applicable facilities in the transmission sector, Mscf CH_4 per Mscf of natural gas sent to sale from or through the facility.

ρ_{CH4} = Density of methane = 0.0192 kg/scf = 0.0192 mt/Mscf.

$Q_{ng,Tran}$ = The total quantity of natural gas that is sent to sale from or through the industry segment at a WEC applicable facility in the reporting year as reported pursuant to part 98, subpart W of this chapter. For onshore natural gas transmission compression, you must use the quantity reported pursuant to § 98.236(aa)(4)(i) of this chapter, in Mscf. For underground natural gas storage, you must use the quantity reported pursuant to § 98.236(aa)(5)(ii) of this chapter, in Mscf. For onshore natural gas transmission pipeline, you must use the quantity reported pursuant to § 98.236(aa)(11)(iv) of this chapter, in Mscf.

(e) For each WEC applicable facility that operates in a single industry segment, the methane waste emissions threshold shall be equal to the value calculated in Equation B-1, Equation B-2, Equation B-3, or Equation B-4 of this section, as applicable. For each WEC applicable facility that operates in two or more industry segments, the facility waste emissions threshold will be calculated using Equation B-5 of this section.

$$TH_{WAF} = \sum_{s=1}^{N} TH_{is,s} \qquad \text{(Eq. B-5)}$$

Where:

TH_{WAF} = The WEC applicable facility waste emissions threshold, mt CH4.

$TH_{is,s}$ = The industry segment waste emissions threshold, as calculated in Equation B-3 or Equation B-4 of this section, for each industry segment “s” at the WEC applicable facility, mt CH_4.

N = Number of industry segments at the WEC applicable facility.

§ 99.21 How will the WEC applicable emissions for a WEC applicable facility be determined?

(a) The total facility applicable emissions for each WEC applicable facility will be calculated using Equation B-6 of this section.

$$E_{TFA,CH_4} = E_{SubpartW,CH_4} - TH_{WAF} \qquad \text{(Eq. B-6)}$$

Where:

$E_{TFA,CH4}$ = The annual methane emissions equal to, below, or exceeding the waste emissions threshold for a WEC applicable facility prior to consideration of any applicable exemptions (*i.e.*, total facility applicable emissions), mt CH_4.

$E_{SubpartW,CH4}$ = The annual methane emissions for a WEC applicable facility, as reported under part 98, subpart W of this chapter for the corresponding reporting year, mt CH_4.

TH_{WAF} = The waste emissions threshold for a WEC applicable facility, as determined in § 99.20(e), mt CH_4.

(b) If the total facility applicable emissions calculated using Equation B-6 of this section are less than or equal to 0 mt, then the WEC applicable emissions are equal to the total facility applicable emissions.

(c) If the total facility applicable emissions calculated using Equation B-6 of this section are greater than 0 mt and the regulatory compliance exemption as specified in § 99.40 applies to the WEC applicable facility, the WEC applicable emissions for that facility are equal to 0 mt.

(d) If the total facility applicable emissions calculated using Equation B-6 of this section are greater than 0 mt and the regulatory compliance exemption as specified in § 99.40 does not apply to the WEC applicable facility, the WEC applicable emissions for each WEC applicable facility will be calculated using Equation B-7 of this section.

$$E_{WA,CH_4} = E_{TFA,CH_4} - E_{Delay,CH_4} - E_{Plug,CH_4} \qquad \text{(Eq. B-7)}$$

Where:

$E_{WA,CH4}$ = The annual methane emissions associated with a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the WEC applicable facility (i.e., the WEC applicable emissions) , mt CH_4. If the result of this calculation is less than 0 mt CH_4, the WEC appliable emissions for the facility are equal to 0 mt CH_4.

$E_{TFA,CH4}$ = The annual methane emissions equal to, below, or exceeding the waste emissions threshold for a WEC applicable facility prior to consideration of any applicable exemptions for the reporting year, mt CH_4.

$E_{Delay,CH4}$ = The quantity of methane emissions exempted, as determined in Equation C-1 of § 99.32, at the WEC applicable facility in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment due to an unreasonable delay in environmental permitting of gathering or transmission infrastructure, mt CH_4.

$E_{Plug,CH4}$ = The total quantity of annual methane emissions, as determined in Equation E-5 of § 99.52, at the WEC applicable facility in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments, attributable to all wells that were permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements, mt CH_4.

§ 99.22 How will the net WEC emissions for a WEC obligated party be determined?

Net WEC emissions for a WEC obligated party, equal to the sum of WEC applicable emissions from all facilities with the same WEC obligated party, as specified in 99.2, will be calculated using Equation B-8 of this section.

$$E_{NetWEC,CH_4} = \sum_{j=1}^{N} E_{WA,CH_4} \qquad \text{(Eq. B-8)}$$

Where:

$E_{NetWEC,CH4}$ = The annual methane emissions subject to the WEC for the WEC obligated party for the reporting year, mt CH_4.

$E_{WA,CH4}$ = The annual methane emissions equal to, below, or exceeding the waste emissions thresholds for a WEC applicable facility “j” as calculated in § 99.21(b) or (d) under common ownership or control of a WEC obligated party, mt CH_4.

N = Total number of WEC applicable facilities under common ownership or control of a WEC obligated party, excluding any WEC applicable facilities for which the regulatory compliance exemption as specified in § 99.40 applies.

§ 99.23 How will the WEC Obligation for a WEC obligated party be determined?

(a) If the net WEC emissions for a WEC obligated party as determined in § 99.22 are less than or equal to zero, the WEC obligated party's WEC obligation is zero and the WEC obligated party is not subject to a waste emissions charge in the reporting year.

(b) If the net WEC emissions for a WEC obligated party as determined in § 99.22 are greater than zero, the WEC obligation will be calculated according to the applicable provisions in paragraphs (b)(1) through (3) of this section.

(1) For reporting year 2024, multiply the net WEC emissions from Equation B-8 of this subpart by $900 per mt CH_4 to determine the WEC obligation.

(2) For reporting year 2025, multiply the net WEC emissions from Equation B-8 of this subpart by $1,200 per mt CH_4 to determine the WEC obligation.

(3) For reporting year 2026 and each year thereafter, multiply the net WEC emissions from Equation B-8 of this subpart by $1,500 per mt CH_4 to determine the WEC obligation.

Subpart C—Unreasonable Delay Exemption

§ 99.30 Which facilities qualify for the exemption for emissions caused by an unreasonable delay in environmental permitting of gathering or transmission infrastructure?

(a) The WEC applicable facility must be in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment as defined in § 99.2.

(b) The total facility applicable emissions for the WEC applicable facility as calculated in accordance with § 99.21(a) must exceed 0 mt.

(c) All requests for information regarding the permit received by either the production entity potentially eligible for the exemption or the entity seeking the environmental permit must not have exceeded the response time requested by the permitting agency, or by the relevant production or gathering or transmission infrastructure entity seeking the permit, or exceeded 30 days if no specific response time is requested.

(d) The WEC facility must report flaring emissions in the reporting year that occurred as a result of a delay in environmental permitting of gathering or transmission infrastructure, and are in compliance with all applicable local, state and federal regulations regarding flaring emissions.

(e) [A set period of months (with exact timing to be specified at final)] must have passed since submission of a complete environmental permit application, as certified by the relevant permitting authority, to construct gathering or transmission infrastructure without approval or denial of the environmental permit application.

§ 99.31 What are the reporting requirements for the exemption for emissions caused by an unreasonable delay in environmental permitting of gathering or transmission infrastructure?

(a) Upon meeting all criteria in § 99.30(a) through (f), you shall report information regarding an exemption for unreasonable delay in permitting of gathering or transmission infrastructure for a given reporting year. The unreasonable delay exemption information to be reported is described in paragraph (b) of this section. The unreasonable delay exemption shall be submitted as described in paragraph (c) of this section.

(b) For each unreasonable delay exemption, the WEC obligated party must report the information specified in paragraphs (b)(1) through (10) of this section.

(1) The company name and name of the facility that submitted the permit application to construct and/or operate gathering or transmission infrastructure.

(2) The name and e-GGRT ID number under part 98, subpart W of this chapter of the production facility impacted by the unreasonable delay in environmental permitting of gathering or transmission infrastructure.

(3) The date of the initial permit request to build gathering or transmission infrastructure.

(4) An attestation that the entity seeking the permit has been responsive to the relevant authority regarding the permit application, that is that the entity has responded to all requests from the permitting authority within the time frame requested by the relevant authority or within 30 days if no timeframe is specified.

(5) For each well-pad impacted by the unreasonable delay in permitting of gathering or transmission infrastructure:

(i) The well-pad ID for each well-pad, as reported under part 98, subpart W of this chapter.

(ii) A listing of methane emissions mitigation activities that are impacted by the unreasonable permitting delay.

(6) The estimated date to commence operation of the gathering or transmission infrastructure if application had been approved before [the set period of months elapsed (exact timing to be specified at final)].

(7) If the application has been approved and operations commenced during the reporting year, the first date that offtake to the gathering or transmission infrastructure from the implementation of methane emissions mitigation occurred.

(8) The beginning and ending date for which the eligible delay limited the offtake of Nnatural gas associated with methane emissions mitigation activities for the reporting year as determined according to § 99.32(a).

(9) The quantity of methane emissions to be exempted due to the unreasonable delay for the reporting year calculated as specified in § 99.32 and the method used to determine the quantity of methane emissions to be exempted (used § 99.32(b)(1); used § 99.32(b)(2)(i); used § 99.32(b)(2)(ii) with K_f based on volume; used § 99.32(b)(2)(ii) with K_f based on time).

(10) Information on all applicable local, state, and federal regulations regarding flaring emissions and the facility's compliance status for each.

(11) For each permit relevant to the exemption, the name/type of permit, permitting agency, and a link to information on the permit (e.g., available through the permitting agency), if available.

(c) Each submittal under this section shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the WEC obligated party in accordance with this section and § 3.10 of this chapter.

§ 99.32 How are the methane emissions caused by an unreasonable delay in environmental permitting of gathering or transmission infrastructure quantified?

(a) Determine the time period associated with the emissions that occurred as a result of the eligible delay within the reporting year as specified in paragraphs (a)(1) and (2) of this section.

(1) The start date of the emissions caused by the delay in the reporting year is the latter of January 1 of the reporting year, or the date on which emissions would have been avoided through commencement of the operation of the gathering or transmission infrastructure if the application to construct and/or operate the gathering or transmission infrastructure had been approved within a set period of months as specified in § 99.31(b)(6).

(2) The end time of the emissions caused by the delay in the reporting year is the earlier of December 31 of the reporting year or the date the emissions caused by the unreasonable delay ends because the infrastructure commenced operation.

(b) For each well-pad or offshore platform at a WEC applicable facility impacted by an unreasonable delay in environmental permitting of gathering or transmission infrastructure, you must calculate the emissions that occurred at the well-pad or offshore platform that were caused by the unreasonable delay according to paragraph (b)(1) or (2) of this section, as applicable.

(1) If the unreasonable delay impacts the entire reporting year, and has resulted in the entire volume of flaring occurring from flare stacks, associated gas flaring, or offshore production flaring, then use the mass CH_4 emissions, in mt CH_4, as reported in § 98.236(m)(8)(iii), (n)(10), and/or (s)(2) of this chapter, as applicable, for the individual flare(s) in the offshore petroleum and natural gas production industry segment and onshore petroleum gas production industry segment used to flare the increased volume of gas from methane emissions mitigation implementation associated with the unreasonable delay in environmental permitting of gathering or transmission infrastructure. If multiple flares are used to flare the increased volume of gas, sum the mass CH_4 emissions for each flare used to flare the increased volume of gas from methane emissions mitigation implementation to determine the cumulative emissions associated with the permitting delay.

(2) If the unreasonable delay impacts only a portion of the reporting year or only a portion of the flaring emissions, determine the eligible emissions as specified in paragraph (b)(2)(i) or (ii) of this section, as applicable.

(i) If you have records to calculate the mass CH_4 emissions from the flare(s) used to flare the increased volume of gas from methane emissions mitigation implementation associated with the unreasonable delay in environmental permitting of gathering or transmission according to the applicable methods in subpart W of this chapter for the specific time period eligible for the exemption, you must calculate the methane emissions for the specific time period eligible for the exemption from each flare used to flare the increased volume of gas from methane emissions mitigation implementation associated with the unreasonable delay. If multiple flares are used to flare the increased volume of gas, sum the mass CH_4 emissions for each flare calculated according to this paragraph to determine the cumulative emissions associated with the permitting delay.

(ii) If you do not have records to calculate the mass CH_4 emissions for the exemption period according to paragraph (b)(2)(i) of this section, then calculate the emissions that occurred at the offshore facility or onshore well-pad caused by the unreasonable delay using Equation C-1 of this section.

$$E_{Delay,CH_4} = E_{MMFlare,CH_4} \times K_f \times X_f \qquad \text{(Eq. C-1)}$$

Where:

$E_{Delay,CH4}$ = Annual CH_4 emissions associated with delay in permitting in the reporting year, mt CH_4.

$E_{MMFlare,CH4}$ = Annual CH_4 emissions from the flare(s) used to flare increased volume of gas from methane emissions mitigation implementation reported in subpart W of this chapter, mt CH_4.

K_f = Eligible timeframe adjustment factor to the CH_4 emissions flaring emissions for partial year exemption period. If you have records of the volume of gas flared from the impacted flare(s) during the exemption period, use the ratio of the volume of gas flared during the exemption period to the total annual volume of gas flared from the impacted flare(s) to determine K_f; otherwise, use the ratio of hours in the exemption period to the total annual hours in the reporting year (8760 or, for leap years, 8784) to determine K_f.

X_f = Fraction of the flared emissions reported in subpart W of this chapter that occurred from the flare(s) due to the unreasonable delay. This fraction can be estimated based on company records of flare emissions prior to the unreasonable delay or through engineering calculations of flare volumes related to other sources vented to the flare(s).

§ 99.33 What are the recordkeeping requirements for methane emissions caused by an unreasonable delay in environmental permitting of gathering or transmission infrastructure?

(a) For each communication the entity seeking the permit has had with the permitting authority regarding the permit application:

(1) The date and type of communication.

(2) The date of the facility’s response to the communication.

(3) Information on whether the facility’s response included modification to the permit application.

(b) Records of values used in the calculation of the emissions that occurred at the well-pad caused by the unreasonable delay.

Subpart D—Regulatory Compliance Exemption

§ 99.40 When does the regulatory compliance exemption come into effect, and under what conditions does the exemption cease to be in effect?

(a) The requirements of this subpart only apply to a WEC applicable facility when the total facility applicable emissions for that WEC applicable facility as calculated in accordance with § 99.21(a) exceed 0 mt CH_4.

(b) The requirements of § 99.41 shall only be in effect when each of the following conditions are met:

(1) A determination has been made by the Administrator that methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 of the Act have been approved and are in effect in all States with respect to the applicable facilities; and

(2) A determination has been made by the Administrator that the emissions reductions achieved by compliance with the requirements described in paragraph (b)(1) of this section will result in equivalent or greater emissions reductions on a nationwide basis as would be achieved by the proposed rule of the Administrator entitled ‘Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review’ (86 FR 63110; November 15, 2021), if such rule had been finalized and implemented.

(c) At such time that the conditions specified in paragraphs (b)(1) and (2) of this section are met, the reporting requirements of § 99.41 shall come into effect beginning with the WEC filing due on the date specified in § 99.5 in the calendar year following the calendar year in which the conditions were met. Imposition of the waste emission charge shall not be made on an applicable facility meeting the requirements for regulatory compliance exemption for methane emissions that occurred during the calendar year during which the conditions are met.

(d) If any of the conditions in paragraph (b)(1) or (2) of this section cease to apply after the Administrator has made the determinations in paragraph (b)(1) and (2) of this section, the reporting requirements of § 99.41 shall cease to be in effect beginning with the WEC filing due on the date specified in § 99.5 in the calendar year during which either of the conditions were no longer met.

§ 99.41 Which facilities qualify for the exemption for regulatory compliance?

(a) The total facility applicable emissions for the WEC applicable facility as calculated in accordance with § 99.21(a) or (d) must exceed 0 mt.

(b) The WEC applicable facility must contain one or more affected facilities or one or more designated facilities.

(c) At the WEC applicable facility, all affected facilities and all designated facilities located at this WEC applicable facility, must have no deviations or violations with the methane emissions requirements of part 60 of this chapter and the methane emissions requirements requirements of an applicable approved state, Tribal, or Federal plan in part 62 of this chapter, including all applicable emission standard, work practice, monitoring, reporting, and recordkeeping requirements.

§ 99.42 What are the reporting requirements for the exemption for regulatory compliance?

(a) A facility eligible for the regulatory compliance exemption that meets the criteria described in § 99.41 shall include information as described in paragraph (b) of this section. A facility that meets the criteria described in § 99.41(a) and (b) but is not eligible for the exemption because it does not meet the criteria in § 99.41(c) shall include information as described in paragraph (d) of this section. The regulatory compliance exemption information shall be submitted as described in § 99.7.

(b) A facility meeting the criteria in § 99.41 must report all of the information specified in paragraphs (b) of this section, as applicable.

(1) For each WEC applicable facility, an assertion that the facility meets all of the eligibility criteria in § 99.41.

(2) The ICIS-AIR ID (or Facility Registry Service (FRS) ID if the ICIS-AIR ID is not available) and EPA Registry ID from CEDRI associated with each affected facility and designated facility located at the WEC applicable facility.

(3) If a report, or reports, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, cover the complete reporting year *(i.e.,* January 1 through December 31, inclusive), then submit as attachment(s) the applicable report(s).

(4) If a report, or reports, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, does not cover the complete reporting year (*i.e.,* January 1 through December 31, inclusive), then submit as attachment(s) the applicable report(s).

(c) If, pursuant to paragraph (b)(4) of this section, you are unable to provide an annual report covering the entire reporting year at the time of the initial submittal specified in § 99.5, you must provide a revised WEC filing on or before such time that an annual report covering the entire reporting year is required to be submitted under the applicable requirements of part 60 of this chapter or an applicable approved state, Tribal, or Federal plan in part 62 of this chapter. This requirement also applies in the case where the initial WEC filing contains an annual report covering only a portion of the reporting year. On or before such time that an annual report is due under the applicable requirements of part 60 of this chapter or an applicable approved state, Tribal, or Federal plan in part 62 of this chapter for the portion of the reporting year for which a previously submitted report does not cover, you must provide a revised WEC filing including the subsequent annual report. The resubmission of the revised WEC filing shall be considered timely under this paragraph if it is made on or before the date that the annual report is due under the applicable requirements of part 60 of this chapter or an applicable approved state, Tribal, or Federal plan in part 62 of this chapter. In such cases where a newly available report indicates one or more deviations or violations from applicable methane emissions requirements that were not previously indicated in the WEC filing for the reporting year (*i.e.*, the WEC applicable facility would no longer qualify for the regulatory compliance exemption), a WEC applicable facility would no longer be subject the reporting requirements in § 99.42(b) and would become subject to the reporting requirements in § 99.42(d) in the revised WEC filing.

(d) If least one of the affected facilities subject to the requirements of part 60 of this chapter or designated facilities subject to the requirements of an applicable approved state, Tribal, or Federal plan in part 62 of this chapter that is contained within your WEC applicable facility has a deviation or violation from its applicable methane emissions requirements (i.e., does not meet the criteria in § 99.41(c)), provide a copy of one report, prepared and submitted in accordance with part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, that demonstrates that the affected facility or designated facility were not in compliance.

(e) A WEC applicable facility's eligibility for the regulatory compliance exemption pursuant to this subpart does not constitute a determination of compliance for part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, for any affected facility or designated facility present at the applicable facility.

(f) A WEC applicable facility's eligibility for the regulatory compliance exemption during a given reporting year does not preclude reassessment of applicable waste emissions charges for that applicable facility upon discovery by the Administrator or a delegated authority of any violation of the methane emissions requirements pursuant to part 60 of this chapter, or an applicable approved state, Tribal, or Federal plan under part 62 of this chapter that implements the emission guidelines contained in part 60 of this chapter, for the affected facilities or designated facilities present at the applicable facility.

Subpart E—Exemption for Permanently Shut-in and Plugged Wells

§ 99.50 What facilities qualify for the exemption of emissions from permanently shut-in and plugged wells?

(a) The total facility applicable emissions for the WEC applicable facility containing permanently shut-in and plugged wells must exceed 0 mt as calculated in accordance with § 99.21(a).

(b) This exemption is applicable to WEC applicable facilities in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment as defined in § 99.2 that permanently shut-in and plugged well(s) during the reporting year. For the purposes of applying this exemption, a permanently shut-in and plugged well is one that has been permanently sealed, following all applicable local, state, or federal regulations in the jurisdiction where the well is located, to prevent any potential future leakage of oil, gas, or formation water into shallow sources of potable water, onto the surface, or into the atmosphere. Site reclamation following placement of a metal plate or cap is not required to be completed for the well to be considered permanently shut-in and plugged for the purposes of this part.

§ 99.51 What are the reporting requirements for the exemption for wells that were permanently shut-in and plugged?

(a) Report the following information for each well at a WEC applicable facility, in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment, that was permanently shut-in and plugged in the reporting year.

(1) Well identification (ID) number as reported in part 98, subpart W of this chapter.

(2) Date the well was permanently shut-in and plugged, which for the purposes of this exemption, is the date when welding or cementing of a metal plate or cap onto the casing end was completed.

(3) The statutory citation for each applicable state, local, and federal regulation stipulating requirements that were applicable to the closure of the permanently shut-in and plugged well.

(4) The equation used to calculate equipment leak emissions attributable to the well (*i.e.*, Equation E-2A or E-2B of this subpart).

(5) The emissions attributable to the well calculated using Equation E-1, E-3, or E-4 of this subpart, as applicable.

(b) The total quantity of methane emissions attributable to all wells that were permanently shut-in and plugged at a WEC applicable facility, in the offshore petroleum and natural gas production or onshore petroleum and natural gas production industry segment, during the reporting year, calculated using Equation E-5 of this subpart.

§ 99.52 How are the net emissions attributable to all wells at a WEC applicable facility that were permanently shut-in and plugged in the reporting year quantified?

(a) For the purposes of this section, the following source types (as specified in part 98, subpart W of this chapter) constitute emissions directly attributable to an offshore petroleum and natural gas production or onshore petroleum and natural gas production well:

(1) Wellhead equipment leaks.

(2) Liquids unloading.

(3) Workovers with hydraulic fracturing.

(4) Workovers without hydraulic fracturing.

(b) Calculate the annual emissions attributable to each well that was permanently shut-in and plugged during the reporting year and included in the submittal pursuant to § 99.51 using Equations E-1, E-3 or E-4 of this section, as applicable.

(1) For onshore petroleum and natural gas production wells that are part of a WEC applicable facility that are permanently shut-in and plugged in reporting years 2025 and later:

(i) Equation E-1 of this section must be used to quantify the methane emissions directly attributable to each permanently shut-in and plugged well.

$$E_{PW,CH_4} = E_{Leaks,CH_4} + E_{LU,CH_4} + E_{WwHF,CH_4} + E_{WwoHF,CH_4} \qquad \text{(Eq. E-1)}$$

Where:

$E_{PW,CH4}$ = The annual quantity of methane emissions directly attributable to an individual well that was permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility, mt CH_4.

$E_{Leaks,CH4}$ = The annual quantity of methane emissions attributable to the well from wellhead equipment leaks as calculated using Equation E-2A or E-2B of this section, as applicable, for the reporting year, mt CH_4.

$E_{LU,CH4}$ = The annual quantity of methane emissions attributable to the well from liquids unloading as reported pursuant to proposed § 98.236(f)(1)(x) or (f)(2)(viii) of this chapter, as applicable, for the reporting year, mt CH_4.

$E_{WwHF,CH4}$ = The quantity of methane emissions attributable to the well from workovers with hydraulic fracturing as reported pursuant to proposed § 98.236(g)(9) of this chapter for the reporting year, mt CH_4.

$E_{WwoHF,CH4}$ = The quantity of methane emissions attributable to the well from workovers without hydraulic fracturing and without flaring as reported pursuant to proposed § 98.236(h)(3)(iv) of this chapter for the reporting year, mt CH_4.

(ii) If equipment leak surveys were used to quantify methane emissions from the permanently shut-in and plugged well and reported pursuant to § 98.236(q) of this chapter in the part 98 report for a WEC applicable facility, Equation E-2A of this section must be used to calculate $E_{Leaks,CH4}$.

$$E_{Leaks,CH_4} = \sum_{p=1}^{N_p} \left(EF_p \times \sum_{z=1}^{x_p} T_{p,z} \right) \times M_{CH_4} \times k \times \rho_{CH_4} \times 10^{-3} \qquad \text{(Eq. E-2A)}$$

Where:

$E_{Leaks,CH4}$ = The annual quantity of methane emissions attributable to the well from wellhead equipment leaks as reported pursuant to § 98.236(q) of this chapter for the reporting year, mt CH_4.

p = Component type as specified in proposed § 98.233(q)(2)(iii) of this chapter.

N_p = The number of component types with detected leaks at the well.

EF_p = The leaker emission factor for component “p” as specified in proposed § 98.233(q)(2)(iii) of this chapter, scf whole gas/hour/component.

M_{CH4} = The mole fraction of CH_4 in produced gas for the sub-basin associated with the well, as reported pursuant to proposed § 98.236(aa)(1)(ii)(I), unitless.

x_p = The total number of specific components of type “p” detected as leaking at the permanently shut-in and plugged well in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$T_{p,z}$ = The total time the surveyed component “z” of component type “p” was assumed to be leaking. If one leak detection survey is conducted in the calendar year, assume the component was leaking from the beginning of the reporting year until the date the well was plugged in accordance with § 99.51(a)(2), hours; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the date the well was plugged in accordance with § 99.51(a)(2), hours; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date the well was plugged in accordance with § 99.51(a)(2), hours; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (*i.e.*, not operating under pressure) using an engineering estimate based on best available data.

k = The factor to adjust for undetected leaks by respective leak detection method, where k equals 1.25 for the methods in proposed § 98.234 (a)(1), (3) and (5) of this chapter; k equals 1.55 for the method in proposed § 98.234(a)(2)(i) of this chapter; and k equals 1.27 for the method in proposed § 98.234(a)(2)(ii) of this chapter. Select the factor for the leak detection method used for the permanently shut-in and plugged well, unitless.

ρ_{CH4} = Density of methane, 0.0192 mt/Mscf.

10^{-3} = Conversion factor from scf to Mscf.

(iii) If equipment leaks by population count were used to quantify methane emission from the permanently shut-in and plugged well and reported pursuant to § 98.236(r) of this chapter in the part 98 report for a WEC applicable facility, Equation E-2B of this section must be used to calculate $E_{Leaks,CH4}$.

$$E_{Leaks,CH_4} = EF_{wh} \times M_{CH_4} \times T \times \rho_{CH_4} \times 10^{-3} \qquad \text{(Eq. E-2B)}$$

Where:

$E_{Leaks,CH4}$ = The annual quantity of methane emissions attributable to the well from wellhead equipment leaks as reported pursuant to § 98.236(r) of this chapter for the reporting year, mt CH_4.

EF_{wh} = The population emission factor for wellheads, as listed in proposed Table W-1 of subpart W of part 98 of this chapter, scf whole gas/hour/wellhead.

M_{CH4} = The mole fraction of CH_4 in produced gas for the sub-basin associated with the well as reported pursuant to proposed § 98.236(aa)(1)(ii)(I) of this chapter, unitless.

T = The total time that has elapsed from the beginning of the reporting year until the date the well was plugged in accordance with § 99.51(a)(2), hours.

P_{CH4} = Density of methane, 0.0192 mt/Mscf.

10^{-3} = Conversion factor from scf to Mscf.

(2) For onshore petroleum and natural gas production wells that are part of a WEC applicable facility that are permanently shut-in and plugged in reporting year 2024, Equation E-3 of this section must be used to quantify the methane emissions attributable to the well:

$$E_{PW,CH_4} = \left(E_{LkQ,CH_4} + E_{LkR,CH_4} + E_{LU,CH_4} + E_{Ww,HF,CH_4} + E_{WwoHF,CH_4}\right) \times \frac{\left(\frac{Q_{ng,PW}}{6}\right) + Q_{oil,PW} + Q_{cond,PW}}{\left(\frac{Q_{ng,WAF}}{6}\right) + Q_{oil,WAF} + Q_{cond,WAF}} \quad \text{(Eq. E-3)}$$

Where:

$E_{PW,CH4}$ = The annual quantity of methane emissions attributable to an individual well that was permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility, mt CH_4.

E_{LkQ} = The WEC applicable facility total annual quantity of methane emissions from equipment leaks reported pursuant to proposed § 98.236(q)(2)(ix) of this chapter for the reporting year, mt CH_4.

E_{LkR} = The WEC applicable facility total annual quantity of methane emissions from equipment leaks reported pursuant to proposed § 98.236(r)(1)(vi) of this chapter for the reporting year, mt CH_4.

E_{LU} = The WEC applicable facility total annual quantity of methane emissions from liquids unloading as reported pursuant to proposed §§ 98.236(f)(1)(x) and (f)(2)(viii) of this chapter for the reporting year, mt CH_4.

E_{WwHF} = The WEC applicable facility total annual quantity of methane emissions from workovers with hydraulic fracturing as reported pursuant to proposed § 98.236(g)(9) of this chapter for the reporting year, mt CH_4.

E_{WwoHF} = The WEC applicable facility total annual quantity of methane emissions from workovers without hydraulic fracturing as reported pursuant to proposed § 98.236(h)(3)(iv) of this chapter for the reporting year, mt CH_4.

$Q_{ng,PW}$ = The total annual quantity of natural gas that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(iii)(C) of this chapter, in thousand standard cubic feet.

6 = Conversion factor from thousand standard cubic feet of natural gas to barrel of oil equivalent.

$Q_{oil,PW}$ = The total quantity of crude oil that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(iii)(D) of this chapter, in barrels.

$Q_{cond,PW}$ = The total quantity of condensate that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(iii)(E) of this chapter, in barrels.

$Q_{ng,WAF}$ = The total quantity of natural gas that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(i)(B) of this chapter, in thousand standard cubic feet.

$Q_{oil,WAF}$ = The total quantity of crude oil that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(i)(C) of this chapter, in barrels.

$Q_{cond,WAF}$ = The total quantity of condensate that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(1)(i)(D) of this chapter, in barrels.

(3) For offshore petroleum and natural gas production wells that are part of a WEC applicable facility that are permanently shut-in and plugged in any reporting year, Equation E-4 of this section must be used to quantify the methane emissions attributable to the well.

$$E_{PW,CH_4} = \left(E_{Leaks,CH_4}\right) \times \frac{\left(\frac{Q_{ng,PW}}{6}\right) + Q_{oil,PW} + Q_{cond,PW}}{\left(\frac{Q_{ng,WAF}}{6}\right) + Q_{oil,WAF} + Q_{cond,WAF}} \qquad \text{(Eq. E-4)}$$

Where:

$E_{PW,CH4}$ = The annual quantity of methane emissions attributable to an individual well that was permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility, mt CH_4.

$E_{Leaks,CH4}$ = The WEC applicable facility total annual quantity of methane emissions from non-compressor component level fugitives (*i.e.*, equipment leaks) reported pursuant to proposed § 98.236(s)(3)(ii) of this chapter for the reporting year, mt CH_4.

$Q_{ng,PW}$ = The total annual quantity of natural gas that is produced and sent to sale from the well in the reporting year as reported pursuant to proposed § 98.236(aa)(2)(iv) of this chapter, in thousand scf.

6 = Conversion factor from thousand standard cubic feet of natural gas to barrel of oil equivalent.

$Q_{oil,PW}$ = The total quantity of crude oil that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(v) of this chapter, in barrels.

$Q_{cond,PW}$ = The total quantity of condensate that is produced and sent to sale from the well in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(vi) of this chapter, in barrels.

$Q_{ng,WAF}$ = The total quantity of natural gas that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(i) of this chapter, in thousand scf.

$Q_{oil,WAF}$ = The total quantity of crude oil that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(ii) of this chapter, in barrels.

$Q_{cond,WAF}$ = The total quantity of condensate that is produced and sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to proposed § 98.236(aa)(2)(iii) of this chapter, in barrels.

(c) Calculate the total emissions attributable to all wells included in the submittal received pursuant to § 99.51 using Equation E-5 of this section:

$$E_{Plug,CH_4} = \sum_{j=1}^{N} E_{PW,CH_4} \qquad \text{(Eq. E-5)}$$

$E_{Plug,CH4}$ = The total quantity of annual methane emissions, as determined in subpart E of this part, at the WEC applicable facility in the onshore petroleum and natural gas production and offshore petroleum and natural gas production industry segments, attributable to all wells that were permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements, mt CH_4.

$E_{PW,CH4}$ = The annual quantity of methane emissions attributable to a well "j" that was permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility calculated using Equation E-1, E-3, or E-4 of this section, as applicable.

N = Total number of wells that were permanently shut-in and plugged during the reporting year in accordance with all applicable closure requirements at a WEC applicable facility.

From: Eric Delzer
To: Eric Delzer
Cc: Brady Pelton; Ron Ness
Subject: NEW PROPOSED METHANE RULE 1-12-24
Date: Friday, January 12, 2024 3:01:01 PM
Attachments: image001.png
image002.png
wec_proposal_preamble_rule.pdf
wec_factsheet.pdf
wec_ria.pdf

Good afternoon air quality working group,

Please see this afternoon's press release from the EPA below. The pre published rule, regulatory impact analysis, and a fact sheet are attached. Comments are due 30 days after publication in the Federal Register. I will start diving into the document and hopefully have some updates for you next week. Have a good weekend!

Biden-Harris Administration Announces Proposed Rule to Reduce Wasteful Methane Emissions from the Oil and Gas Sector to Drive Innovation and Protect Communities

January 12, 2024

Contact Information

EPA Press Office (press@epa.gov)

WASHINGTON –Today, the U.S. Environmental Protection Agency (EPA) announced a proposed rule to tackle wasteful methane emissions from the oil and gas sector, delivering on Congress' directive in the Inflation Reduction Act to incentivize adoption of industry best practices that reduce pollution. The proposed rule will assess a charge on certain large emitters of waste methane from the oil and gas sector that exceed emissions intensity levels set by Congress. Working in tandem with unprecedented funding secured by President Biden under the Inflation Reduction Act and recently finalized technology standards for the industry issued in December 2023, the proposed Waste Emissions Charge encourages the early deployment of available technologies and best practices to reduce methane emissions and other harmful air pollutants before the new standards take effect.

"Under President Biden's leadership, EPA is delivering on a comprehensive strategy to reduce wasteful methane emissions that endanger communities and fuel the climate crisis," said **EPA Administrator Michael S. Regan.** "Today's proposal, when finalized, will support a complementary set of technology standards and historic resources from the Inflation Reduction Act, to incentivize industry innovation and prompt action. We are laser-focused on working collectively with companies, states, and communities to ensure that America leads in deploying technologies and innovations that aid in the development of a clean energy economy."

"I'm pleased to see the Biden Administration move forward with this critical program to slow climate change and protect our one and only planet," said **Senator Carper, Chairman of the Senate Environment and Public Works Committee**. "We know methane is over 80 times more potent than carbon dioxide at trapping heat in our atmosphere in the short term. Thankfully, the Methane Emissions Reduction Program – which Congress adopted as part of the Inflation Reduction Act – will incentivize producers to cut wasteful and excessive methane emissions during oil and gas production."

"For too long it has been cheaper for oil and gas operators to waste methane rather than make the necessary upgrades to prevent leaks and flaring. Wasted methane never makes its way to consumers, but they are nevertheless stuck with the bill," said **Rep. Frank Pallone, Jr., Ranking Member of the House Energy and Commerce Committee.** "The Methane Emissions Reduction Program and the proposed Waste Emissions Charge will ensure consumers no longer pay for wasted energy or the harm its emissions can cause. I commend EPA for taking the next step to hold the largest polluters accountable and protect American families from dangerous methane pollution."

"EPA's proposal for a fee on oil and gas methane pollution implements the clean air protections for Americans that were part of the Inflation Reduction Act," said **Fred Krupp, President of the Environmental Defense Fund**. "It's common sense to hold oil and gas companies accountable for this pollution. Proven solutions to cut oil and gas methane and to avoid the fee are being used by leading companies in states across the country."

Methane is a climate "super pollutant" that is more potent than carbon dioxide and responsible for approximately one third of the warming from greenhouse gases occurring today. The oil and natural gas sector is the largest industrial source of methane emissions in the United States.Quick reduction of these methane emissions is one of the most important and cost-effective actions the United States can take in the short term to slow the rate of rapidly rising global temperatures.

EPA issued a final rule in December 2023 to sharply reduce methane emissions and other harmful air pollution from new and existing oil and gas operations. In addition, EPA is working to implement the three-part framework of the Inflation Reduction Act's Methane Emissions Reduction Program.

First, EPA is partnering with the U.S. Department of Energy (DOE) to utilize resources provided by Congress in the Inflation Reduction Act to provide over $1 billion dollars in financial and technical assistance to accelerate the transition to no- and low- emitting oil and gas technologies, including funds for activities associated with low-producing conventional wells, support for methane monitoring, and funding to help reduce methane emissions from oil and gas operations.

Second, EPA is working with industry and other stakeholders to improve the Greenhouse Gas Reporting Program and increase the accuracy of reported methane emissions.

Third, with today's proposal, EPA seeks to encourage facilities with high methane emissions to meet or exceed the levels of performance set by Congress – performance that is already being achieved by leading oil and gas companies.

The Inflation Reduction Act established a Waste Emissions Charge for methane from certain oil and gas facilities that report emissions of more than 25,000 metric tons of carbon dioxide equivalent per year to the Greenhouse Gas Reporting Program. As directed by Congress, the Waste Emissions Charge starts at $900 per metric ton of wasteful emissions in 2024, increasing to $1,200 for 2025, and $1,500 for 2026 and beyond, and only applies to emissions that exceed the statutorily specified levels.

EPA's proposed rule addresses details regarding how the charge will be implemented, including the calculation of the charge and how exemptions from the charge will be applied. Facilities in compliance with the recently finalized Clean Air Act standards for oil and gas operations would be exempt from the charge after certain criteria set by Congress are met. The agency expects that over time, fewer facilities will face the charge as they reduce their emissions and become eligible for this regulatory compliance exemption.

In the meantime, the Waste Emissions Charge will help encourage the oil and gas industry to stay on target to lower emissions. Oil and natural gas operations with methane emissions in excess of the emissions intensity levels established in the Inflation Reduction Act can reduce or eliminate any charge by deploying readily available technologies to reduce harmful and wasteful emissions. This program will help to level the playing field for industry leaders already employing best practices and drive near-term opportunities for more widespread methane reductions while EPA and states work toward full implementation of the Clean Air Act standards.

Together, EPA's Clean Air Act rule and the three Inflation Reduction Act provisions will advance the adoption of clean, cost-effective technologies, reduce wasteful practices, and yield significant economic and environmental benefits, while driving continued innovation in methane detection, monitoring, and mitigation techniques.

For more information, please visit the Methane Emissions Reduction Program website.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Eric Delzer
To: Reiten, John R.
Cc: Brady Pelton; Jonathan Fortner
Subject: RE: Rules
Date: Monday, January 15, 2024 3:20:25 PM
Attachments: image001.png
NEW PROPOSED METHANE RULE 1-12-24.msg

John,

Thanks for checking in. You can add the Waste Emission Charge rule that the EPA pre published on Friday afternoon (information in attached email). It looks like the comments on it will be due 30 days after publication in the federal register. The Waste Emissions Charge (WEC) for methane applies to petroleum and natural gas facilities that emit more than 25,000 metric tons of CO2 equivalent per year as reported under Subpart W of the Greenhouse Gas Reporting Program, that exceed statutorily specified waste emissions thresholds set by Congress, and that are not otherwise exempt from the charge. The WEC starts at $900 per metric ton for 2024 reported methane emissions, increasing to $1,200 per metric ton for 2025 emissions, and $1,500 per metric ton for emissions years 2026 and later.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Monday, January 15, 2024 2:56 PM
To: Jonathan Fortner <JonathanFortner@lignite.com>; Brady Pelton <bpelton@ndoil.org>; Eric Delzer <edelzer@ndoil.org>
Subject: Rules

Hi all,

Can you double-check the list of rules that I am tracking? I think I have them all, but I wanted to get a couple of pairs of eyes on it.

If you don’t see something, PLEASE flag it.

Federal Rule	Regulatory Agency
Executive Order 13990	Office of the President
North Dakota Resource Management Plan	BLM
Mercury and Air Toxics Standards (MATS)	EPA
Greenhouse Gas // Carbon Rule 2.0	EPA
Gas Pipeline Safety	PHMSA
Endangered Species Act Rule #1	FWS
Endangered Species Act Rule #2	FWS
Endangered Species Act Rule #3	FWS
Mineral Leases and Leasing Process	BLM
NEPA Revisions Phase 2	CEQ
Air Emissions Reporting Requirements	EPA
Conservation and Landscape Health	BLM
National Highway System- GHG Emissions	FHWA
DAPL DEIS	USACE
Natural Asset Companies	SEC
Applicability of Emergency Exemptions	FMCSA
Travel Management Plan	DPG
Baseline Water Quality Standards	EPA
OOOO (b)	EPA
OOOO (c)	EPA
Regional Haze	EPA
Coal Combustion Residuals Legacy Rule	EPA

NORTH DAKOTA PETROLEUM COUNCIL

GOVERNOR'S VIP DINNER

AGENDA

Governor's Residence, 1151 N 4th St. Bismarck
Park on the SW corner of the Capitol grounds, use East entrance.

Social 6:30-7:15 pm
Dinner 7:15 pm

Host Remarks

Governor Doug Burgum

Comments

- Todd Slawson, President, Slawson Companies, NDPC Chairman of the Board.
- Harold Hamm, Executive Chairman, Continental Resources
- Chris Wright, CEO, Liberty Energy
- Lynn Helms, Director, ND Department of Mineral Resources

BAKKEN NOW | WILLISTON BASIN PETROLEUM CONFERENCE

FIVE BILLION BAKKEN BARRELS

From: Ron Ness
To: Reiten, John R.
Subject: FW: sending agenda to VIP guests for 5/15
Date: Tuesday, May 7, 2024 8:04:30 AM
Attachments: Outlook-ku343kqk.jpg
Outlook-erhgqijz.jpg
Agenda WPBC VIP Dinner at Gov Residence 5 15 2024.pdf

We will make some of these for the table spots. Reva will get them to Connie.

From: Reva Kautz <rkautz@ndoil.org>
Sent: Monday, May 6, 2024 6:11 PM
To: Ron Ness <ronness@ndoil.org>
Subject: sending agenda to VIP guests for 5/15

attached is the updated agenda for VIP dinner for you to email out to your guest list

Reva Kautz

Communications Director

North Dakota Petroleum Council

100 West Broadway, Suite 200

PO Box 1395

Bismarck, ND 58501

Office: 701.557.7744

rkautz@ndoil.org

www.ndoil.org

From: Reva Kautz
To: Reiten, John R.
Cc: Reva Kautz
Subject: VIP Dinner at the Governor"s Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference
Date: Monday, March 11, 2024 12:26:48 PM
Attachments: Outlook-z5qoydeq.jpg
Outlook-biqzifkk.jpg

You don't often get email from rkautz@ndoil.org. Learn why this is important

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

I am requesting your assistance regarding the upcoming VIP dinner that Ron Ness said he has scheduled with you already on Wednesday, May 15, 2024, at the Governor's residence from 6:30 to 8:30 PM. This is in conjunction with the Williston Basin Petroleum Conference.

I not only want to confirm this reservation at the Governor's residence but I have been tasked with creating a special invitation to the VIPs and I am hoping to find out:

- who caters the meal? or do we need to arrange for the catering?
- parking
- max capacity
- other details to share with those invited

Please, let me know if there is a different contact person I need to coordinate this event details with.

In appreciation,

Reva Kautz
Communications Director
North Dakota Petroleum Council
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501
Office: 701.557.7744
rkautz@ndoil.org
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American
Petroleum
Institute

June 5, 2024

Ms. Yvette M. Fields
Division Chief, Fluid Minerals Division
Bureau of Land Management
1849 C St. NW, Room 5633
Washington, DC 20240
Email: yfields@blm.gov

Dear Ms. Fields:

As you know, the recently finalized Waste Prevention Rule is scheduled to become effective on June 10, 2024. API and its members appreciate BLM's efforts to create rational, workable requirements for limiting unnecessary venting and flaring. However, API and its members believe BLM should provide additional clarification and guidance on how it expects operators to comply with the rule's provisions. Like BLM, we want the implementation of this rule to be a success; therefore, prior to the quickly-approaching effective date, we request written answers to address the vital questions below:

- **Avoidable / Unavoidable Losses**
    - Will the BLM use the current forms and codes for the avoidable/ unavoidable loss categories for reporting or will BLM use new forms and codes? If new forms are involved, when is BLM planning to introduce those? How should operators report in the meantime?
    - Since BLM has not released these forms, we are requesting that BLM delay the reporting requirements until those forms have been released to the public and companies have had time to work them into their systems. When BLM is considering timelines, please be aware that companies will need adequate time to incorporate the new codes and forms into complex internal corporate reporting systems. We therefore request that you leave sufficient time for these electronic considerations as you establish the reporting deadlines.
    - What if operators exceed the limit in your unavoidable category? Is the entire volume then avoidable or just the overage? This is a particular concern given the problems in the formulas for flare calculations described below.

- **Flare Calculation Methodologies**
    - *Please note that these flare calculations were not included in the proposed rule that was released for public comment; consequently, API was not able to present these points in our comments. Based on the problems with these equations, we encourage you either to remove the prescribed definitions (i.e., return to current processes), or solicit public comment on the existing equations. In either case, we do not believe these are ready to be debuted for reporting based on July 1. Using the existing state methodologies will not require duplicate calculations at the corporate level.*
    - The High-Pressure flow calculation does not have an input to account for "lease usages" of gas (ex: fuel for engines, burners, etc.).
    - The formula provided § 3179.71 does not work for low pressure flare estimation because many of the key variables are unavailable in most instances. Since low pressure (LP) flaring is largely unavoidable, this problematic formula does not add additional value or royalties; therefore, we recommend its deletion.
        - "M" (Previous 6 months of flaring) does not exist in many areas.
        - "Vg/Vo"(Previous 6 months of production) is proportional only to HP GOR. In many cases, this calculated value would easily be over double the actual value of the low pressure flare (and possibly even higher).
        - "Vop"(Production while LP Flare is active) is difficult to discern without advanced automation that does not exist on many wells.
        - "Vs" (Gas Vol sold while flaring) is often not available for most LP sources because most existing facilities do not include FMP meters specific to LP sources.
    - When does BLM expect industry to start using the prescribed formula, given its challenges for high pressure and low pressure flares? How does this impact the July 1st requirement to start tracking unavoidable lost flaring ratio (scf/bbl) limit?
    - Will there be an approval process to use an alternative flare calculation methodology, given the robustness of existing methods (e.g., New Mexico requirements)?
- **Equipment Considerations**
    - Will any lead time being provided to allow metering manufacturers to get existing ultrasonic meters API 22.3 certified?
- **Waste Minimization Plans (WMPs)**
    - Does BLM have a template for WMPs? Some states have templates for their requirements. To avoid duplication and ensure consistent reporting and data, will using the state forms be sufficient?
    - What should a self-certification look like? Will BLM have a form?
    - The rule also requires operators to submit, as part of their WMP, the anticipated initial production and decline rates for the first three years of production from each well. This material information can be uncertain and typically constitutes

proprietary and company confidential information. As such, operators are reluctant to supply this information as part of their WMP if it could become public.

    - To meet this requirement, particularly where basin-level declines rates are well understood, can operators supply publicly available data for similar wells (i.e., information, including production profiles, developed by third-party firms)?
    - If BLM believes public information will not suffice, and the production and decline rates are required, how will BLM ensure that this data is safeguarded from public disclosure? Appropriate protective measures should include secure systems for submitting data, limits on which individuals in the BLM field office will have access to the data, limits on sharing this data with other state and federal agencies, etc.
    - Will BLM allow manned facilities flexibility in installing auto-ignitors because of the continuous monitoring?

- **Public Outreach**
  - Does BLM plan to hold any public workshops on implementation or deliver additional guidance? As operators become more familiar with the mechanics of implementation, other questions will certainly arise and a consistent forum for ongoing dialogue would be beneficial.

If you have any questions about the issues raised in this letter, please do not hesitate to contact me at any time by phone at (202) 682-8372 or by email at emmerta@api.org.

Thank you in advance for your prompt attention to these important issues. We look forward to working with you to achieve the successful implementation of this rule.

Sincerely,

Amy Emmert

Amy Emmert
Senior Policy Advisor
American Petroleum Institute

From: Eric Delzer
To: Wallevand, Erik; Axt, Philip J.; Reiten, John R.
Cc: Brady Pelton
Subject: Waste Prevention Rule Industry Concerns
Date: Tuesday, June 11, 2024 11:08:57 AM
Attachments: Outlook-zilu2ldy.png
Waste Prevention Compliance BLM Letter 06 05 final sent.pdf

Good morning gentlemen,

I'm not sure if you've seen it yet, but I just wanted to pass along this letter that API sent the BLM last week regarding the industry's concerns with being able to comply with the waste prevention rule. The effective date is soon approaching, and the BLM has given no guidance on these issues.

Regards,

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: WBPC
To: WBPC; Micaela Rud
Subject: WBPC 2024 Attendee Tips & Tricks
Date: Thursday, May 9, 2024 4:22:35 PM
Attachments: image003.jpg
Importance: High

2024 Williston Basin Petroleum Conference Attendee Tips & Tricks

We want to thank you for registering for the upcoming conference in Bismarck, May 14-16th! We are excited for you to see our SOLD-OUT exhibit hall, listen to our fantastic speakers, and participate in our breakout sessions. We have over 260 companies exhibiting, with 2,000 attendees already registered!

Please see below for information we felt would be helpful in your preparations for next week.

TIPS & TRICKS

- Suggested attire:
  - Tuesday – business casual, company logo attire for exhibitors
  - Wednesday – business, company logo attire for exhibitors
  - Thursday – business casual
- Forecast:
  - Typical ND weather for this time of year – 60s and 70s during the day, chilly at night. Bring a jacket to be safe!
- Conference & Times:
  - You will receive a barcode to scan at check-in for a faster experience. Please check your email (including your spam and junk folders) for an email from GTR Registration.
  - All listed times are Central Daylight Time.
  - Registration opens at 8 a.m. on Tuesday, May 14th in the Bismarck Event Center Lobby. Please use door E42, off of 5th Street. Click here to see map layouts at the Event Center.
  - Please be aware that parking is limited!
- Join Us:
  - 5 Billion Bakken Barrel Celebration | Tuesday, May 14, 5:00 – 7:00 p.m. | *Sponsored by Halliburton*
  - Networking Social | Wednesday, May 15, 4:30 -6:30 p.m.
  - ND Oil PAC Social | Wednesday, May 15, 7:00 – 10:00 p.m. | The Bismarck Hotel Dakota Ballroom 800 S 3rd Street. Minimum $20 donation to attend. NO CAMERAS OR VIDEOING PERMITTED.
- Need a pick-me-up?
  - Visit the 3andMe kiosk by registration, or Sweet Creation's food truck outside door E42!

Visit www.wbpcnd.com for more information.

We can wait to see you!!

Micaela Rud
Executive Assistant
North Dakota Petroleum Council

General: 701-223-6380
Direct: 701-204-7345
mrud@ndoil.org

From: Reva Kautz
To: Reva Kautz
Subject: Help Create a Buzz about the Williston Basin Petroleum Conference Happening NEXT WEEK!
Date: Wednesday, May 8, 2024 4:40:38 PM
Attachments: image001.png
Outlook-c4nzscmf.jpg
I"m attending WPBC (LinkedIn Post).jpg

Some people who received this message don't often get email from rkautz@ndoil.org. Learn why this is important

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

We are excited that you have registered for the Williston Basin Petroleum Conference, and we look forward to seeing you in a couple of days!

Please consider using the attached graphic and share that you are going to be at the Bismarck Event Center next week on your social media platforms.

Let's encourage others to register for the conference as well. All conference updates can be found online: www.WBPCND.com

#WBPCND2024

NDPC Logo

MAY 14-16, 2024
BISMARCK, ND

Williston Basin Petroleum Conference Update

Thank you for being one of the 1,800 already registered to attend the Williston Basin Petroleum Conference next week!

Sensational Technology Panel Discussions

Don't miss the breakout sessions providing technical solutions being used in North Dakota's Williston Basin.

1 PM on May 15th: Advancing Bakken Technology

The Trek to 5 Billion Bakken Barrels	**Unconventional Enhanced Oil Recovery**	**East Nesson Bakken EOR Pilot**	**Methane Foam Injection**
Preston Page Dakota Energy	**Brad Aman** Continental Resources	**Mark Pearson** Liberty Resources	**Mohammed Piri** University of Wyoming

3 PM on May 15th: Williston Basin: Technology and Opportunity

E-fracs = More Rock Stimulation	**Shaun Pyka**	Halliburton
Mitigating Offset Frac Impact Through Low-Flow Method	**Chris Collard**	Devon Energy
Bakken Production Optimization Program - 10 Years of Partnership	**Jim Sorensen**	EERC
Bakken Produced Fluids Chemistry & Evolution	**Beth Kurz**	EERC

New Addition to the Conference Agenda on May 16th

Learn about the geopolitical importance of the shale revolution in the Israel-HAMAS War from leaders of the Council for a Secure America during their main stage presentation at 8:25 AM on Thursday, May 16.

Matt Most and Jennifer Sutton will be offering a post-conference bonus session providing a deeper dive on the Council for a Secure America Israel-HAMAS War report at 11:45 AM on Thursday.

Network at the Amazing Expo on Tuesday and Wednesday

Engage and connect with over 300 indoor and outdoor exhibitors. This is a great time to build your business!
Note: There is no trade show on Thursday, May 16th.

Attend the 5 Billion Bakken Barrel Celebration

We will be celebrating the milestone of having produced five billion barrels of oil in the Bakken at 5pm on Tuesday, May 14th. Want to find out what the limited-edition commemorative gift is? Don't be late to the party!

Encourage others to register for the conference online.
For all the conference details visit www.wbpcnd.com.

The conference is sponsored by the North Dakota Petroleum Council, North Dakota Department of Mineral Resources, North Dakota Petroleum Foundation, and the Petroleum Technology Research Centre.

For more information, call 701-223-6380 or email: wbpc@ndoil.org.

Unsubscribe

In appreciation,

Reva Kautz
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100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501
Office: 701.557.7744
rkautz@ndoil.org
www.ndoil.org

From: Brady Pelton
To: NDPC
Subject: Special Invitation to 2024 Williston Basin Petroleum Conference: May 14-16, 2024 in Bismarck, North Dakota
Date: Monday, April 1, 2024 8:45:52 AM
Attachments: image.png
image.png
image002.png
image003.png
image004.png
image001.wmz
image006.png
Importance: High

Good morning!

On behalf of the North Dakota Petroleum Council, it is my distinct privilege to invite you to the **31st Annual Williston Basin Petroleum Conference** taking place **May 14-16, 2024** at the **Bismarck Event Center** in Bismarck, North Dakota. Below are links to additional information on this premier oil and gas industry event, including the Conference agenda, list of presenters, exhibitor information, and more!

As our special guest to the event, we are pleased to offer you registration to this exciting event for a registration fee of $50! To register, simply click on the green “REGISTER” link below and complete the registration process under the “Government” registration type. As you enter the Registration Information page to enter your information, be sure to select “Yes” when asked if you have a promocode and enter **24Gov** in the promocode box at the bottom to take advantage of the low-fee registration option.

We look forward to seeing you at this year’s Williston Basin Petroleum Conference! As always, please do not hesitate to contact me with any questions.

SPECIAL GUEST LOW-FEE REGISTRATION

Register under the “Government” registration type and enter code 24Gov in the “promocode” box of the Registration Information page to take advantage of the $50 registration fee option.

BRADY PELTON
Vice President & General Counsel

North Dakota Petroleum Council
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

701.223.6380 – Main
701.557.7743 – Direct
701.260.2479 – Cell
bpelton@ndoil.org

www.NDOil.org | www.NDOilFoundation.org

From: Reva Kautz
To: Reva Kautz
Subject: A Powerful Beginning to the 31st Annual Williston Basin Petroleum Conference in Bismarck, ND
Date: Monday, April 15, 2024 5:01:16 PM
Attachments: image.png
Outlook-x2nzunrk.jpg
Outlook-gftairym.jpg
image.png

We are so glad you are already registered for the conference!
Please forward this email to those who should consider joining us in Bismarck in May.

You can see the full agenda for the conference with the WBPC website www.wbpcnd.com.

We look forward to seeing you!

Reva Kautz
Communications Director
North Dakota Petroleum Council
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www.ndoil.org

NORTH DAKOTA
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701.223.6380 | ndpc@ndoil.org | www.NDOil.org

March 26, 2024

U.S. Environmental Protection Agency
EPA Docket Center
Air and Radiation Docket
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

RE: Waste Emissions Charge Proposed Rules Official Comments- Docket ID No. EPA–HQ–OAR–2023–0434 (Submitted Electronically at Federal eRulemaking Portal. https:// www.regulations.gov)

The North Dakota Petroleum Council (NDPC) is grateful for the opportunity to provide input on the proposed implementation of the Waste Emissions Charge (WEC) as part of the Methane Emissions Reduction Program (MERP) that was mandated by Congress under the Inflation Reduction Act (IRA). Established in 1952, the NDPC is a trade association that represents more than 550 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipelines, transportation, mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky Mountain Region. NDPC members have a vested interest in making this program a workable structure that they can operate under while continuing to provide the energy security on which the nation relies.

Background

The oil and gas industry is an integral part of the U.S. economy, and environmental stewardship is a priority of our members. In 2022, oil and natural gas accounted for 72.5% of the energy consumption in the U.S. (Source: U.S. EIA), an increase of 5% since 2021 (68.5%)[1]. The oil and gas industry has further led the way by decreasing total emissions by nearly 66% across seven major producing regions since 2011, while natural gas production increased by 179% (Figure 01).

North Dakota is ranked third in the nation in the production of oil, and NDPC's members produce 98 percent of the oil in North Dakota. Even with the remarkable growth of the Bakken Play, North Dakota's air quality remains high; there are no air quality non-attainment areas in North Dakota, and North Dakota produces approximately 3.5 million cubic feet of natural gas per day and 1.273 million barrels of oil per day. Furthermore, North Dakota has taken many steps to reduce flaring, we are currently at a 95% gas capture rate,[2] and we have decreased our methane emissions in the

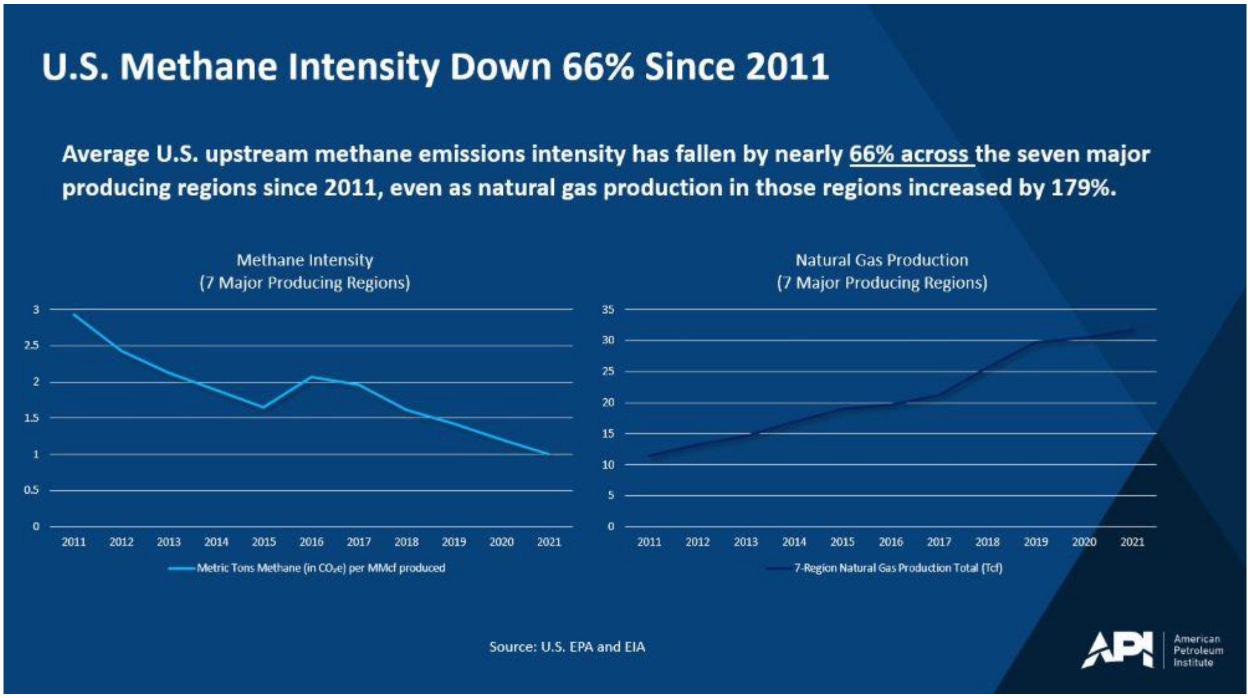
---

[1] U.S. Energy Information Administration. (2023, December). *U.S. Oil and Natural Gas Wells by Production Rate*. Retrieved from the U.S. Energy Information Administration website: US Oil and Gas Wells by Production Rate - U.S. Energy Information Administration (EIA)

[2] North Dakota Industrial Commission. (2023, December). Oil and Gas Production Report[1]**.** Bismarck, ND: Author.

Williston Basin by more than 30% since 2018[3]. Most recently, the NDPC worked with the North Dakota legislature to pass legislation further incentivizing a reduction in flaring through the Clean Natural Gas Capture and Emissions Reduction Program.

Figure 01



U.S. Methane Intensity Down 66% Since 2011

Average U.S. upstream methane emissions intensity has fallen by nearly 66% across the seven major producing regions since 2011, even as natural gas production in those regions increased by 179%.

Source: U.S. EPA and EIA

This decrease of methane emissions showcases commitment to environmental stewardship and how innovation over regulation is a superior approach to drive methane reductions. We have demonstrated, and are continuing to demonstrate, our ability to manage fossil fuels and fossil fuel-powered technologies to neutralize the climate impact of our operations. The industry is taking a proactive approach to resource development to integrate gas conservation and commercialization – maximizing gas capture and minimizing emissions. By capturing these emissions, we provide more natural gas to the market for society's beneficial use, significantly reduce energy poverty, improve energy security, and boost the worldwide economy. Overall, our resource development provides a major net-benefit to humanity and helps power a modern world.

Our commitment to environmental stewardship and compliance is also well demonstrated and documented by the EPA. In October of 2023, the EPA Region 8 office commissioned flyover inspections of 796 facilities in the Williston Basin the day after a major blizzard which brought severe weather impacts to the entire region. Despite the extreme weather conditions immediately preceding the inspections, the EPA only found a 1% noncompliance rate regarding flares, which were addressed as soon as operators were able to dig out and safely make it to their facilities.

---

[3] Independent Petroleum Association of America. (2023). Methane Emissions Decline in Top Oil and Gas Basins (2018-2022). EPA Greenhouse Gas Reporting Program.

Oil and gas development is vital to North Dakota's economy, providing substantial revenues to the state and local governments that support roads, schools, public safety, and other critical services. The oil and natural gas industry also provides billions of dollars in annual economic impact and supports thousands of jobs. Taxes from oil and gas production account for 52 percent of North Dakota's tax revenue. Since 2008, North Dakota's oil and gas production tax revenues have generated over $26 billion and have provided over $1.8 billion for education and $5.9 billion in funding for communities and infrastructure across the state. The taxes have also contributed $6.9 billion to the North Dakota Legacy Fund, which serves as a perpetual source of revenue for the state's general fund and tax relief for its citizens.

Approximately 25 percent of North Dakota's oil production occurs within the exterior boundaries of the Fort Berthold Indian Reservation (FBIR) of the MHA Nation, also referred to as the Three Affiliated Tribes. The MHA Nation and the State of North Dakota have a historic oil and gas tax revenue sharing agreement, allowing a significant share of taxes assessed against oil and natural gas produced within FBIR to flow to MHA Nation members. MHA Nation generates most of its revenue based on the volume of oil extracted from within its territories, with oil and gas royalties and tax revenues constituting 80 percent of the Nation's budget.[4] This revenue is used to provide healthcare, housing, child care, elder care, as well as many other social services to Tribal communities.

Accordingly, the NDPC is very concerned about the details of the proposed WEC rule as written and how the implementation of said program may have severe negative repercussions on the industry, state and tribal economies, and the greater energy security of the country. The WEC is one of several broad and overreaching regulatory reforms being implemented that appears to ignore the disproportionately negative impacts on small independent producers and disadvantaged communities.

This proposed action may force producers to plug and abandon wells before the end of their useful life. That would have a direct negative economic impact on all North Dakotans, including Tribal members, due to decreases in royalties and declining economic activity from impacted oil and gas production. Over-regulation of the oil and gas industry increases production costs and discourages investment in the industry with little, if any, environmental benefit. Any increases in production and compliance costs will likely be passed on to the consumer, driving up the price of energy at a time when demand is rapidly increasing. This would lead to higher electricity, heating fuels, food, and transportation prices, which disproportionately impacts low-income Americans. As inflation has increased, we have seen tangible evidence of this over the last few years.

Many North Dakota mineral lessees are small businesses that run wells with little room for unplanned changes or increased operating costs from taxes or production fees that would render their wells uneconomical. Even though these wells are considered small producers, they make up a large portion of the wells in North Dakota and across the nation. The lessees may now be faced with a choice to continue their livelihood at great expense that may never be recovered or abandon those

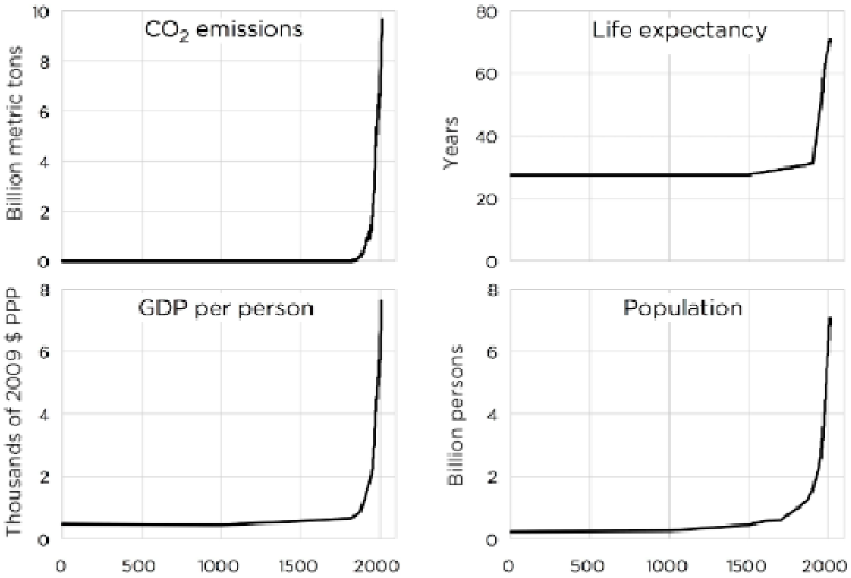
---

[4] Declaration of Mark N. Fox, Chairman of the Mandan, Hidatsa & Arikara Nation, also known as the Three Affiliated Tribes at 2-3, Standing Rock Sioux Tribe v. U.S. Army Corps of Eng'rs, No. 1:16-cv-01534-JEB (D.D.D. Apr. 19, 2021).

locations. The loss of this production not only impacts the energy security of the nation but the economic security of thousands of North Dakotans who depend on the royalties generated from these wells. These small producers all support other small service businesses that may also be forced into uncertain economic situations.

Recently, a letter submitted to the Council on Environmental Quality by eleven members of Congress highlighted that "Energy consumption, GDP, and life expectancy are intrinsically tied (Figure 02). Adults living at or below the poverty level are five times more likely to report poor or fair health than those living with incomes above 400 percent of the federal poverty level."[5] The Congressional letter further reported that "in 2020, 34 million U.S. households (27 percent of all U.S. households) reported difficulty paying energy bills or reported that they had kept their home at an unsafe temperature because of energy cost concerns. More than one third of Americans say they reduced or skipped basic expenses, such as medicine or food, to pay an energy bill in 2022, and the cost for an average household rose approximately $10,000 in the first two years after President Biden took office. Instead of relying on government subsidies to offset high energy costs, we should be focusing on policies that encourage more U.S. energy production and reduce the cost of energy for all Americans."

Figure 02



North Dakota has a population of approximately 779,261, and the per capita income in the state is about $41,800, similar to the national average. The median household income is slightly lower than the national average at $71,970. Approximately 11.5 percent of the North Dakota population lives below the poverty line, close to the national rate, and many are struggling right now due to soaring inflation and increased costs of goods and services.[6]

---

[5] Congressional Western Caucus. (2024). *Comments on the Council on Environmental Quality's Environmental Justice Scorecard* [Letter to Brenda Mallory, Chair, Council on Environmental Quality]. U.S. House of Representatives.

[6] *North Dakota*, CENSUSREPORTER.ORG, https://censusreporter.org/profiles/04000US38-north-dakota/ (last visited Dec. 13, 2023).

The oil and gas industry offers higher average wages compared to other sectors and has spurred the development of energy courses and training programs at various colleges and universities in the state. According to a 2021 economic impact study, almost 50,000 jobs in North Dakota are a result of the oil and gas industry with a payroll totaling $4.5 billion.[7] The industry has provided people with the opportunity to make a living wage and support themselves and their families.

The economic benefit from North Dakota oil and gas production has lifted thousands of historically poor, disadvantaged, and underserved residents of rural and Tribal communities out of poverty and has brought unmeasurable improvements to health and social care in the state. Affordable energy prices benefit all sectors of the American public, and cost-effective regulation of the energy industry only benefits human health and the environment.

In light of these very real implications, we have many concerns about the proposed language in the WEC rule. We rightly question whether the potential negative impacts of this proposed regulation outweigh the diminishing returns on emissions reduction after we have demonstrably led the world in emission reduction for decades. We hope the EPA gives due consideration to the constructive feedback we have provided regarding the current proposed WEC language in our official comments detailed in the following section.

Official Comments

Definitions

The NDPC recommends that the EPA ensure consistency and harmonization in defining key operational terms across various regulations, particularly focusing on production, boosting, and gathering facilities. It is crucial that these definitions align with those established in the NSPS OOOO, OOOOa, and now OOOOb and OOOOc, which are the primary air quality regulations governing oil and gas operations. This alignment will ensure clarity and reduce regulatory complexities for industry stakeholders.

The NDPC also raises concerns regarding the EPA's approach of aggregating emissions across all reported segments to determine if they surpass the 25,000 metric ton threshold. This methodology may lead to the imposition of emissions estimation requirements on additional sites and operating companies that are currently exempt. Such a shift will likely result in an undue administrative and operational burden on the industry.

Furthermore, the EPA's reliance on historical categorizations to justify the impacts of its regulations may be flawed, especially given the significant changes proposed in 40 CFR 98, Subpart W regarding the definition of Boosting and Gathering. These modifications could extend the scope of 'WEC Applicable Facilities,' impacting a larger segment of the industry than anticipated. The EPA

---

[7] DEAN BANGSUND & NANCY HODUR, NORTH DAKOTA OIL AND GAS INDUSTRY ECONOMIC CONTRIBUTION ANALYSIS SUMMARY REPORT 4 (2022), available at https://ndpetroleumfoundation.org/wp-content/uploads/2023/03/2021-Petroleum-Economic-Contributions-Summary.pdf.

must reevaluate these impacts in light of the changes to ensure a fair and accurate assessment of the regulatory burden on the industry.

The NDPC also offers the following suggestions for amended definition language for “operator” and “owner”:

> **Operator:**
> “Operator” means the person or persons responsible for the overall operation of a stationary source.
>
> **Owner:**
> “Owner” means the person or persons who own a stationary source or part of a stationary source.

Exemptions

The NDPC has identified significant concerns with the exemptions outlined in the proposed WEC rule. In their current form, these exemptions are unworkable and fail to align with the intent of the legislation.

Under the terms of the proposal, the Regulatory Compliance Exemption would not be available for at least three years (because this is how long EPA has, in the final methane rule, allowed for states to submit their 111(d) plans and for EPA to review and approve or disapprove them) and once available, will be virtually impossible to achieve. In other words, EPA has effectively interpreted the Regulatory Compliance Exemption out of the statute.

The requirement for zero violations or non-compliance across all facilities in a basin is unattainable. Reporting a deviation is a compliance demonstration for reporting under the NSPS OOOO suite of rules. Reporting of deviations does not mean non-compliance; this is compliance. This standard does not account for minor incidents like a single leaking thief hatch or unlit pilot, which can occur even in operations striving for compliance, and reporting of such is a proper compliance mechanism. The NDPC suggests that this criterion is too stringent and does not reflect the legislation's intent to encourage proactive compliance efforts. Instead, it proposes that self-reported and corrected deviations should not automatically disqualify a facility from claiming an exemption.

The EPA's stipulation that all facilities must have implemented both NSPS OOOOb and OOOOc programs before claiming this exemption is problematic. Under 40 CFR 98, Subpart W, a 'facility' refers to an entire basin, and it is unreasonable to disqualify an entire basin for minor deviations at a single well site. The NDPC suggests a revision where exemptions should be applicable at the individual facility level rather than at the basin or sub-basin level. Furthermore, the NDPC supports the American Exploration and Production Council’s (AXPC) comments on the regulatory compliance exemption and urges the EPA to develop an approach that ensures the availability and utility of the intended exemption for regulatory compliance.

NDPC proposes that the exemption for plugged wells should include the netting of removed sources such as pneumatic valves. This proposal recognizes the totality of emissions reduction efforts. The EPA's position that only flaring emissions can be exempted in cases of delayed pipeline construction is also problematic. The cascading effect of such delays on multiple emission sources should be considered, including incremental emissions related to pipeline construction delays.

The EPA's requirement for compliance with state and local regulations to claim exemptions is also concerning. The EPA lacks jurisdiction in this matter and the 30-42 month threshold for permit approval is excessively long, fails to reflect the legislative intent, and potentially worsens emissions issues. EPA should not wait until all state or federal OOOOc plans are adopted to establish the availability of the Regulatory Compliance Exemption. A state-by-state approach is more aligned with Congressional intent than the current proposal and will ensure efficiency in the plan development process, further incentivize operators' compliance with OOOOc, and ensure more operators are eligible for the exemption. Finally, NDPC asserts that additional reporting beyond the annual NSPS OOOOb and OOOOc reports should not be necessary for demonstrating compliance. The EPA already has access to these reports and certifications, and additional reporting requirements would be redundant.

The EPA needs to use more realistic, facility-level criteria for exemptions, that consider the intent of the legislation to incentivize compliance without imposing unreasonable burdens or penalties for minor deviations. These suggested revisions would make the exemptions more attainable and reflective of the operational realities within the industry.

Subpart W

The expectation for operators to estimate their 2024 emissions based on the version of Subpart W that will be in effect in 2024 is both unreasonable and potentially unfeasible. Given that the finalized rule will significantly impact reported emissions for 2024 and is not expected to be released until August of the same year, operators are left without adequate time to establish the necessary measurement and monitoring systems to comply with the new requirements. The NDPC has already communicated the various supply chain issues and delays that would hinder timely compliance with the impending final rule. Therefore, expecting compliance with the final rule to estimate emissions at WEC Applicable Facilities for the calendar year 2024 is unrealistic. This not only poses a potential compliance issue, but could also inadvertently penalize operators for circumstances beyond their control.

The Global Warming Potential (GWP) for methane changing from 25 to 28 is equally concerning. This amendment effectively lowers the threshold for the imposition of the Methane Tax and may inadvertently categorize operations previously below the threshold as above it, subjecting them to new tax liabilities. Such a change could have considerable financial implications for operations and could lead to unexpected burdens on the industry, particularly on those operators that are not currently in a position to absorb these additional costs.

NDPC urges the EPA to reconsider these aspects of the proposed rule and suggests a more measured and practical approach that takes into account the operational realities and constraints faced by the industry. Adjustments to the implementation timeline for the new Subpart W requirements and a reevaluation of the proposed GWP change are crucial to ensure that operators can meet the regulatory expectations without undue hardship.

Energy Allocation

NDPC strongly recommends EPA amend the Facility Methane Intensity calculation to define the numerator, WEC Facility Methane Emissions, as the portion of the emissions attributable to the natural gas sent to sales or facility throughput. Without this allocation of emissions to the energy produced, the assessment of facilities' methane intensity is inherently biased - the methane associated with the total fluids (oil, NGLs) production is included in the numerator (methane associated with oil and gas production), but only the gas portion of the total sold is used in the denominator.

Applying an energy allocation basis would resolve this issue by allocating emissions based on energy of products received by the facility, where these volumes are already reported to the GHGRP through subpart W. Furthermore, NDPC supports the AXPC's comments on the Facility Methane Emissions calculation and recommends the EPA amend the calculation to define the WEC Facility Methane Emissions as the portion of the emissions attributable to the natural gas sent to sales or facility throughput.

Netting

NDPC advocates for an expanded scope of netting. Netting should not be confined solely to WEC applicable facilities but allow for the inclusion of all facilities, especially those that do not seek the "Regulatory Compliance Exclusion." Facilities eligible for exemptions should also be considered for netting. This more inclusive approach would encourage broader emissions reduction efforts beyond only the facilities that are subject to the WEC, supporting a more comprehensive environmental strategy.

Netting should be permitted at the parent company level across all segments and facilities. Such a policy would align with the intent of the IRA by enabling companies to target the most cost-effective emissions reductions throughout their operations. By restricting netting to the permit or operating company level, the rule could inadvertently discourage operators from pursuing further reductions once the WEC threshold is met. NDPC notes that certain emissions, such as those resulting from compressor engine slip, are inherently more challenging to mitigate, and a policy that limits netting to the operating company level could stifle innovation and progress in emissions reduction, and result in a plateau effect at the threshold of the WEC.

Furthermore, NDPC has concerns over the EPA's broad definition of "owner," which could potentially encompass equity interest partners. The current definition is problematic because many owners are "non-operators" and do not exercise operational control, nor do they have the capacity to directly influence emissions reductions. Imposing potential WEC liability on these non-operational owners would be incongruous with long-standing financial practices within the industry and could introduce unwarranted complexities and conflicts.

Lastly, the current proposal permits netting only within the assets under a permitted entity or subsidiary level. Such a restricted approach may lead to unintended and counterproductive actions by oil and gas operating companies rather than fostering industry-wide enhancements in emissions control. NDPC calls for a full revision of the netting provisions to incorporate these suggestions that would promote more extensive and effective emissions reductions across the oil and gas industry, in line with both legislative intent and practical industry operations.

<u>WEC Filings and Financial Obligations</u>

The provisions of the proposed rule need adjustments to reflect operational realities and Congressional intent. The due date for the WEC fee is set for March 1$^{, 2025}$. This timing is impractical, particularly as operators have yet to align with the finalized Subpart W rule expected later in the year. The filing due date should be shifted to November 1, 2025, followed by an additional 60 days to submit the required payment, aligning with the reasonable expectation that the EPA will have concluded its review of Subpart W filings by this later date.

Error corrections are also a point of contention with the proposed due date. NDPC requests a more reasonable timeline that permits adjustments to the prior year’s emissions until November 1st of each calendar year. The responsibility for errors pertaining to acquired facilities should not carry over to a new owner, which would prevent punitive measures for issues outside a new owner’s control.

NDPC challenges the notion that all owners share responsibility. Instead, we suggest that only the operating entity at the time should be accountable. This aligns with historical regulatory practices that do not require unanimous owner agreement for fees. This stance recognizes the operational transfer of control and argues for proportional responsibility up to the point of ownership transfer, rather than a blanket obligation for the entire year.

NDPC also questions the need for an annual designated representative filing. Such filings should only be triggered by changes in the designated representative, rather than as a routine annual requirement. Interest charges for late corrections, if necessary, are deemed excessive. Such charges should commence only after a revised November 1st deadline, and only if the EPA upholds its end of the agreement by providing a timely assessment.

The call for third-party audits at the cost of the industry is unnecessary. The existing filings and documentation should be sufficient to meet EPA’s informational needs. Imposing third-party audits is viewed as an unnecessary financial and administrative burden on the industry.

Finally, NDPC insists on a reciprocal commitment from the EPA concerning the handling of overpayment refunds. A 45-day resolution period for the industry to correct discrepancies should be matched by a similar commitment from the EPA to process any refunds, maintaining a balanced and equitable approach. The EPA must commit to completing reviews and process refund payments promptly to best reflect a fair and timely administrative process.

Conclusion

NDPC recognizes the challenges the EPA faces in creating and implementing this WEC program. However, we are very concerned that the EPA may have overreached in its selective implementation of the MERP under the IRA and believe that the existing proposed WEC language is clearly not in line with Congressional intent. Senator Joe Manchin, who was instrumental in the crafting and passage of the IRA, provided clear insight into Congress's intentions in his June 2023 letter to EPA Administrator Regan.[8] Senator Manchin expressed that the "EPA has clearly missed the boat to implement this program in a fair manner, consistent with Congressional intent."

Senator Manchin further stated that "the statute clearly intends to exempt marginal wells and smaller producers from the fee. EPA must make it clearly understood that those entities not subject to the current Subpart W Greenhouse Gas Reporting Program are not subject to EPA fees under MERP." "The MERP mandates that EPA revise Subpart W to make it more empirically based and allow for the use of individual estimates for emissions levels based on company-specific analyses. EPA must improve the accuracy and quality of its emissions factors, and EPA must provide operators a straightforward process for using the data they have available when reporting emissions. For example, MERP fees should not be calculated using arbitrary emissions factors based on metrics like "miles of gathering pipeline" for operators who have facility-based measurements that more accurately assess actual leaks, unrealistic assumptions like constant operation of pneumatic devices, or treating all compressors as having the same degree of methane slip when operators have data showing their actual facilities are performing better. EPA should draw reasonable boundaries around the definition of individual "facilities" (such as pad site, compressor site, or reporting field) for emissions intensity calculations so that aggregations of large amounts of disparate wells and gathering lines does not lead to charging a fee on marginal facilities that Congress intended to exempt or on facilities that have minimal actual emissions. To assist individuals and small businesses engaged in energy production, EPA should provide a publicly available, easily understandable explanation of the calculation method for CO2-equivalent emissions, methane intensity, and other key calculations necessary to understand the requirements of MERP. Fee calculation methodologies should be flexible and equitable to account for the wide range of oil and gas operations. For example, an operator primarily producing natural gas will be affected differently than one primarily producing crude oil with limited amounts of associated gas."

NDPC strongly urges the EPA to reconsider the current provisions of the proposed WEC rule and amend the language to include the suggestions above to further align with clear Congressional intent. Congress intended the MERP to be a tool to incentivize further emissions reduction. It was not intended to be used as a punitive action against the industry to stifle oil and gas production; increase energy, food, and consumer good costs; further erode the health, prosperity, and well-being of communities; and compromise our national energy security.

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[8] Manchin, J. (2024). Concerns regarding selective implementation of the Inflation Reduction Act and methane emissions fees. Retrieved from https://www.manchin.senate.gov/newsroom/press-releases/manchin-urges-epa-to-improve-implementation-of-methane-emissions-reduction-program

We expect the EPA will acknowledge our constructive feedback regarding specific amendments to the provisions of the proposed rule that will make this a more workable framework under which companies can reasonably operate, and one that does not disproportionately affect small operators and North Dakota environmental justice communities.

Thank you for your consideration.

Sincerely,

Ron Ness
President
North Dakota Petroleum Council

Submitted via regulations.gov

March 26, 2024

Mr. Shaun Ragnauth
Climate Change Division
Office of Atmospheric Programs
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Attention: Docket ID EPA-HQ-OAR-2023-0434

RE: Waste Emissions Charge for Petroleum and Natural Gas Systems

Dear Mr. Ragnauth:

The American Petroleum Institute, American Exploration and Production Council, American Fuel and Petrochemical Manufacturers, Independent Petroleum Association of America, LNG Allies - The USLNG Association, Energy Workforce and Technology Council, Western States Petroleum Association, Alaska Oil and Gas Association, Kentucky Oil and Gas Association, Louisiana Mid-Continent Oil and Gas Association, Michigan Oil and Gas Association, New Mexico Oil and Gas Association, North Dakota Petroleum Council, Ohio Oil and Gas Association, The Petroleum Alliance of Oklahoma, Pennsylvania Independent Oil and Gas Association, Texas Independent Producers and Royalty Owners Association, Utah Petroleum Association, Gas and Oil Association of West Virginia, and Petroleum Association of Wyoming (collectively, the "Industry Trades") respectfully submit the below comments on the Environmental Protection Agency's (EPA) Proposed Rule "Waste Emissions Charge for Petroleum and Natural Gas Systems" (89 FR 5318, January 26, 2024) ("WEC").

Reducing methane emissions is a shared priority for EPA and the oil and natural gas industry. However, the Industry Trades have significant concerns with EPA's proposed implementation of the WEC. The proposed rule fails to meet the statutory requirements and objectives set forth by Congress in the Inflation Reduction Act (IRA) Methane Emissions Reduction Program (MERP). Rather than incentivizing emissions reductions, the proposed rule would maximize fees paid under the WEC and disincentivize accelerated emissions reductions.

The Industry Trades and our members have engaged constructively with EPA on the "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems", and the "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review", and look forward to continued dialogue and engagement with EPA on the WEC to ensure the final rule reflects Congressional intent, incentivizes emissions reductions, and does not unfairly and unreasonably impose additional costs on American energy production. If you have any questions regarding the content of these comments, please contact Ryan Steadley at steadleyr@api.org.

Sincerely,

Holly Hopkins

Holly A. Hopkins

Vice President, Upstream Policy
American Petroleum Institute

cc:
Sharyn Lie, EPA Lie.Sharyn@epa.gov
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INDUSTRY TRADES INTERESTS

The **American Petroleum Institute (API)** is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. Gross Domestic Product (GDP). API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators, and marine transporters, as well as service and supply companies, providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

The **American Exploration and Production Council (AXPC)** is a national trade association representing 30 of the largest independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of providing positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

American Fuel and Petrochemical Manufacturers (AFPM) is a national trade association whose members comprise most U.S. refining and petrochemical manufacturing capacity. AFPM is the leading trade association representing the makers of the fuels that keep us moving, the manufacturers of the petrochemicals that are the essential building blocks for modern life, and the midstream companies that get our feedstocks and products where they need to go. To receive necessary materials and to move their essential products to satisfy growing demand, AFPM members depend on the timely development of, and enhancements to, transportation infrastructure such as pipelines.

The **Independent Petroleum Association of America (IPAA)** represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, which will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The **USLNG Association**—operating under the global brand name of **LNG Allies (LNGA)**—is the only independent organization focused solely on advancing the interests of the USLNG industry. We are a 501(c)(6) nonprofit trade association. Our members include USLNG exporters and project developers, U.S. natural gas producers, and allied service companies, including engineering firms, equipment makers, and global gas infrastructure providers. As the leading industry voice, we promote effective public policy and communicate the domestic and global benefits of USLNG exports. We also conduct and sponsor research and policy analysis; organize workshops, conferences, and issue briefings; and provide information about USLNG exports. Internationally, we work to open new markets for USLNG exports, expand existing markets, and establish strategic relationships. Our mission is to help bring the climate, environmental, economic, and geostrategic benefits of USLNG to the world.

Energy Workforce and Technology Council (EWTC) is the national trade association for the energy technology and services sector, representing over 300 companies and employing more than 650,000 energy workers, manufacturers, and innovators in the energy supply chain. Energy Workforce members have employees in all 50 states. Membership ranges from large energy services companies with global operations all the way down to small family-owned well-servicing companies that operate locally within the U.S. Energy Workforce member companies provide the United States and the world with energy in the most environmentally safe, efficient, and responsible way possible, and our sector is leading the development of technology that will ensure our country maintains energy security that will power our economy and protect our way of life for generations to come. Energy Workforce members are active in multiple segments of the oil and natural gas supply chain starting with production of oil and natural gas through well servicing, drilling, well stimulation, completions, and distribution.

Western States Petroleum Association (WSPA) is a non-profit trade association that represents companies that account for the bulk of petroleum exploration, production, refining, transportation and marketing in the five western states of Arizona, California, Nevada, Oregon, and Washington. WSPA's headquarters is located in Sacramento, California. Additional WSPA locations include offices in Torrance, Concord, Ventura, Bakersfield, and Olympia, Washington. WSPA is dedicated to ensuring that Americans continue to have reliable access to petroleum and petroleum products through policies that are socially, economically and environmentally responsible. We believe the best way to achieve this goal is through a better understanding of the relevant issues by government leaders, the media and the general public. Toward that end, WSPA works to disseminate accurate information on industry issues and to provide a forum for the exchange of ideas on petroleum matters.

The **Alaska Oil and Gas Association (AOGA)** is a professional trade association whose mission is to foster the long-term viability of the oil and gas industry for the benefit of all Alaskans. We represent the majority of companies that are exploring, developing, producing, transporting, refining, or marketing oil and gas on the North Slope, in the Cook Inlet, and in the offshore areas of Alaska.

The **Kentucky Oil and Gas Association (KOGA)** represents the interests of its members who are primarily small independent producers of oil and natural gas that operate for the most part, low volume/low pressure wells across the Commonwealth of Kentucky.

The **Louisiana Mid-Continent Oil and Gas Association (LMOGA)** serves exploration and production, refining, transportation, marketing, and mid-stream companies as well as other firms in the fields of law, engineering, environment, financing, and government relations. LMOGA's mission is to promote and represent the oil and gas industry operating in Louisiana and the Gulf of Mexico by extending the representation of our members to the Louisiana Legislature, state and federal regulatory agencies, the Louisiana congressional delegation, the media, and the general public.

The **Michigan Oil And Gas Association (MOGA)** represents the exploration, drilling, production, transportation, processing and storage of crude oil and natural gas in the State of Michigan. MOGA has nearly 650 members including independent oil companies, major oil companies, the exploration arms of various utility companies, diverse service companies and individuals. Organized in 1934, MOGA monitors the pulse of the Michigan oil and gas industry as well as its political, regulatory, and legislative interest in the state and the nation's capital. MOGA is the collective voice of the petroleum industry in Michigan, speaking to the problems and issues facing the various companies involved in the state's crude oil and natural gas business.

The **New Mexico Oil and Gas Association (NMOGA)** is a coalition of oil and natural gas companies, individuals, and stakeholders dedicated to promoting the safe and environmentally responsible development of oil and natural gas resources in New Mexico. Representing over 200 member companies, NMOGA works with elected officials, community leaders, industry experts, and the general public to advocate for responsible oil and natural gas policies to increase public understanding of industry operations and contributions to the state.

Established in 1952, the **North Dakota Petroleum Council (NDPC)** is a state trade association that represents more than 600 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipelines, transportation, mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky Mountain Region; to promote opportunities for open discussion, lawful interchange of information, and education concerning the petroleum industry; to monitor and influence legislative and regulatory activities on the state and national level; and to accumulate and disseminate information concerning the petroleum industry to foster the best interests of the public and industry. Our members have a vested interest in making this program a workable structure that we can operate under while continuing to provide the energy security the nation relies on.

The **Ohio Oil and Gas Association (OOGA)** is a trade association with members representing the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio. OOGA membership is comprised of independent, major national, and major international oil and natural gas companies—all focused on the exploration, discovery, and production of crude oil, natural gas, and associated liquids in Ohio, along with companies representing all aspects of the midstream and downstream operations, including pipelines, processors, and refineries.

The **Petroleum Alliance of Oklahoma (PAO)** represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. Our members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas. Our members are committed to extracting, producing, transporting, and refining crude oil and natural gas in a safe and environmentally-sound manner. The Alliance's members have made significant strides in reducing and/or eliminating greenhouse gas (GHG) emissions and continue to pursue technologies and innovative solutions to detect, reduce and eliminate methane emissions. Our members provide abundant, clean-burning natural gas that has enabled the United States to become the global leader in greenhouse gas emissions reductions.

The **Pennsylvania Independent Oil and Gas Association (PIOGA)**, historically the principal nonprofit trade association representing Pennsylvania's independent crude oil and natural gas producers, marketers, service companies and related businesses, continues to expand its focus as it embraces the entire oil and gas spectrum, from upstream through midstream and downstream entities. As tremendous success in accessing Marcellus and Utica reserves has dramatically increased supply with a resulting sharp decline in commodity prices, PIOGA has broadened its emphasis to seek expanded markets and additional uses for natural gas and related products. This has led to an expansion of PIOGA's focus to more fully include pipeline operators and end-users such as power generation, industrial, and manufacturing consumers of methane, ethane and related commodity products. Working together, we help members accomplish that which they cannot achieve alone.

Founded in 1946, **Texas Independent Producers and Royalty Owners Association (TIPRO)** is one of the oldest and largest oil and natural gas trade associations in the state of Texas. TIPRO's nearly 3,000 members include small family-owned businesses and the largest publicly traded producers, in addition to large and small mineral estates and trusts creating a unique and impactful voice for the industry. Collectively, TIPRO members produce nearly 90 percent of the oil and natural gas in Texas and own mineral interests in millions of acres across the state.

The **Utah Petroleum Association (UPA)** is a statewide oil and gas trade association established in 1958 representing companies involved in all aspects of Utah's oil and gas industry. UPA members range from independents to major oil and natural gas companies, including upstream E&P companies, midstream operators, refineries, and a broad range of service providers. We represent nearly 90% of the crude oil production in the state and all 5 of the state's refineries. Our members are widely recognized as industry leaders responsible for driving technology advancement resulting in environmental and efficiency gains.

The **Gas and Oil Association of West Virginia (GO-WV)** is a non-profit organization that works to promote and protect all aspects of the oil and natural gas industry in West Virginia. GO-WV currently has over four hundred and fifty (450) member companies, which include independent producers, fully integrated energy companies, companies engaged in various aspects of service and supply activities, and consulting companies. The members of GO-WV operate in nearly every county of West Virginia and employ thousands of people located in the State of West Virginia.

The **Petroleum Association of Wyoming (PAW)** represents the state's oil and gas industry including production, midstream processing, pipeline transportation, and oil field service companies. The Association also represents affiliated companies offering oil and gas related legal, accounting, oilfield services, and consulting services. Eighty-five percent of the oil and gas companies operating in Wyoming are classified as small businesses.

Executive Summary

Although claiming to base the WEC Proposed Rule on a plain reading of the statutory text, EPA has in reality designed a program that countermands the plain intent of Congress and in many cases goes far beyond the enabling statute by limiting the scope of emissions netting, creating unattainable exemption criteria, and establishing an unworkable administrative timeline, among other issues described herein. To facilitate review of our comments, we have listed below our primary concerns with the Proposed Rule, with our detailed comments following the same sequence.

1) EPA's failure to adequately consider the New Source Performance Standards OOOOb/Emissions Guidelines OOOOc, Subpart W, and WEC as interconnected regulations undermines the industry and the administration's shared goal of reducing methane emissions with technically feasible and cost-effective solutions.

2) Operators should be able to net at the parent company level. Allowing netting at the parent company level is appropriate because it would fully implement Congress's clear purpose of mitigating the impact of the fee program and incentivize emission reductions across operations under the same parent company.

3) The exemption language EPA proposes is unduly restrictive across all exemption categories contemplated by Congress.

   a. EPA should adopt a case-by-case process for determining whether an unreasonable delay in permitting has occurred for the purpose of that exemption since the proposed brightline criteria for contribution to delay and defining unreasonable delay are inappropriate and impractical. The exemption should include other methane emissions that result from an unreasonable delay in environmental permitting for gathering or transmission infrastructure.

   b. The regulatory compliance exemption should be available as soon as a state or federal program is in effect for the state(s) in which the facility is located. For the purposes of the regulatory compliance exemption, "applicable facility" should be understood to mean the "affected facility" under NSPS OOOOb or state equivalent pursuant to EG OOOOc. The applicable/affected facility should be considered "in compliance" with methane emission standards unless a violation is proven through adjudication or is admitted by the owner or operator; a proven or admitted violation should disqualify only the applicable/affected facility from the exemption.

   c. EPA should expand the exemption for permanently shut-in and plugged wells to include all methane emissions from all equipment and processes that were associated with the permanently shut-in and plugged well. Recordkeeping and reporting for this exemption should not be duplicative with other existing well closure requirements.

4) EPA must establish a workable timeline between Subpart W reporting and validation and WEC filing and validation. The WEC filing should occur only when Subpart W reports have been validated to avoid an untenable cycle of additional payments or refunds.

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List of Attachments

Attachment A – Previous API Comments on NSPS OOOOb and EG OOOOc, Docket No. EPA-HQ-OAR-2021-0317

Attachment B – Previous Industry Trade Comments on Proposed Subpart W Revisions, Docket No. EPA-HQ-OAR-2023-0234

PROPOSED WASTE EMISSIONS CHARGE FOR PETROLEUM AND NATURAL GAS SYSTEMS (WEC)
DOCKET ID: EPA-HQ-OAR-2023-0434

Due to the unreasonably short duration of the comment period for this Proposed Rule, the Industry Trades have been unable to respond to all of EPA's comment solicitations. Although EPA granted a 15-day comment extension, API had requested a 30-day extension[1] given the complex nature of the proposed WEC rule and connections to EPA's proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas System ("Subpart W")[2], and EPA's proposed New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review ("Methane Rule" or "OOOObc")[3].

While every effort has been made to consider the effects of our comments, unintended consequences may still occur due to the unknown outcome of the final Subpart W revisions, which will be the basis for calculating the WEC. The following guiding principles should therefore be observed for our comments:

- Owners or Operators should have the ability to maximize netting and exemptions when calculating their WEC.
- WEC filing and payment process should be streamlined and consider Subpart W validation process.
- Interest and penalties should not be imposed on updated WEC filings and payments resulting from EPA validation of Subpart W or WEC.

Finally, due to the myriad of uses for the term "facility", we have endeavored to articulate when "facility" refers to a geographically discrete stationary source (c.f. New Source Review), an affected or designated facility under OOOObc, or a reporting facility or segment under Subpart W. We also provide comments on "facility" definition for the purposes of the WEC in Comment 7.0

1.0 Regulatory Coherence

EPA must administer the WEC in a manner that is reasonable and consistent with other related rulemakings (OOOObc and Subpart W). EPA's piecemeal regulatory actions jeopardize timely and effective WEC implementation[4,5].

1.1 EPA failed to adequately consider OOOObc, Subpart W, and WEC as interconnected regulations aiming to reduce methane emissions with technically feasible and cost-effective solutions.

The proposed WEC is statutorily connected to OOOObc and Subpart W with the overall aim of reducing methane emissions with technically feasible and cost-effective solutions. As of the date of this comment letter, OOOObc has only recently been finalized, but Subpart W has not. Despite the overlapping development of these rules (to meet rushed and impractical timelines), EPA has failed to recognize the interdependence of these complex regulations and therefore jeopardizes timely and effective implementation of the WEC. EPA must administer all

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[1] EPA-HQ-OAR-2023-0434-0140

[2] 88 FR 50282

[3] 87 FR 74702

[4] https://www.manchin.senate.gov/imo/media/doc/merp_letter_to_epa.pdf?cb

[5] https://www.epw.senate.gov/public/_cache/files/b/0/b0559828-89b1-4456-820c-51ae1ecb7315/98783E8E1057069E7FB16CBB7B32FDE3.subpart-w-letter-final-12.13.23.pdf

three of these regulations in a reasonable and coherent manner. Procedurally, EPA has not given a meaningful opportunity to comment on the proposed WEC rule since Subpart W revisions have not been finalized.

1.2 Unreasonable implementation of OOOObc would make the regulatory compliance exemption from the WEC unachievable and meaningless.

API submitted detailed comments[6] on EPA's proposed Methane Rule, which are the basis for the regulatory compliance exemption for the WEC. A copy of these comments is included as Attachment A, and key comments are summarized below.

- **Emissions detected from covers and closed vents system do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.** As proposed, a WEC applicable facility must have no deviations or violations to be eligible for the regulatory compliance exemption. An unreasonable application and interpretation of the "no identifiable emissions" standard would make the regulatory compliance exemption practically impossible to meet.
- **EPA underestimates the number of affected facilities under NSPS OOOOb, which further increases the difficulty in qualifying for the regulatory compliance exemption.** With a proposed criterion of no deviations or violations for an entire WEC applicable facility (as understood to be an entire Subpart W reporting basin), an increased number of NSPS OOOOb affected facilities would make qualifying for the exemption practically unachievable.
- **Only a proven or admitted violation, not a deviation or accusation of violation, should make an applicable/affected facility ineligible for the regulatory compliance exemption.** As discussed further in Comment 4.0, the regulatory compliance exemption should be based on no proven or admitted violations rather than deviations or mere accusations of violations.
- **The WEC exemption should be based on the OOOObc affected or designated facility basis and take into account the duration of a noncomplying event.** Compliance with OOOObc is based on an "affected or designated facility" level (i.e. the distinct equipment or collection of equipment regulated as the affected or designated facility under OOOObc, hereafter referred to only as "affected facility" for clarity and simplicity) while the WEC regulatory compliance exemption is proposed on the "WEC applicable facility" level (i.e., the collection of discrete sites with OOOObc affected facilities within a Subpart W reporting basin). The regulatory compliance exemption should also be based on the OOOObc affected facility level, which would allow operators to exempt from WEC those sites with OOOObc affected facilities that are in compliance even if other sites in the larger WEC applicable facility do not qualify for the exemption. The exemption should also incorporate the duration of a noncomplying event. For example, if a noncomplying event lasts for 24 hours, the exemption should be available for the remainder of the reporting year.
- **The WEC disincentivizes early compliance with EG OOOOc and other voluntary reduction initiatives based on proposed netting calculations.** Early adoption of EG OOOOc and other voluntary methane reduction actions may make facilities unable to net for determination of the WEC since WEC facilities less than 25,000 metric tons of CO_2e are proposed to be ineligible to participate in netting. The inability to net methane reductions from voluntary efforts may disincentivize implementation of cost-effective methane solutions before implementation of a state's respective EG OOOOc state plan. The 25,000 metric ton CO_2e

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[6] EPA-HQ-OAR-2021-0317-2428, EPA-HQ-OAR-2021-0317-3817, EPA-HQ-OAR-2021-0317-3819, EPA-HQ-OAR-2021-0317-3838, and EPA-HQ-OAR-2021-0317-3849.

threshold could therefore be treated as a "floor" for methane reduction efforts since the proposed rule does not encourage any further reductions beyond that level. Furthermore, EPA's proposed "all or nothing" approach for the regulatory compliance exemption does not accelerate EG OOOOc compliance since the exemption is unavailable until all state (or federal) plans are effective. Therefore, the Industry Trades recommend that WEC applicable facilities with less than 25,000 metric tons of CO_2e be eligible for netting and that a OOOObc applicable facility should be eligible for the regulatory compliance exemption as soon as the applicable plan is effective for the state(s) in which it is located; see Comment 2.1 and Comment 4.1, respectively.

1.3 Subpart W revisions must support efficient and accurate reporting of methane emissions as the basis for the WEC.

Subpart W is now unique among all other subparts of the GHGRP in that emissions information submitted under Subpart W will serve regulatory purposes not shared by other industries that report under other subparts. Efficient and accurate reporting of methane emissions under Subpart W would facilitate fair and accurate WEC calculations and fee amounts. API along with other trade organizations submitted detailed comments[7] concerning EPA's proposed revisions to Subpart W, which are the basis for calculating the WEC beyond 2024. This comment letter is included as Attachment B and key comments are summarized below:

- **EPA should avoid any potential double-counting or over-estimation of emissions across source types.** Double counting or over-estimation of emissions, especially through the proposed other large release event requirements and tiered approach to flare "combustion efficiency", would unfairly overestimate the WEC.
- **Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities should be reported under Subpart C and should not be included under Subpart W.** Reporting combustion emissions under Subpart W is inconsistent with how combustion is reported for all other industries under 40 CFR Part 98 and, given the interconnectedness of Subpart W with the WEC rule, such emissions cannot be considered "waste". As such, non-flaring combustion emissions should not be subject to any fees for "waste" and should be removed from Subpart W and captured in Subpart C. At a minimum, combustion emissions should not be included in the WEC fee calculation as those emissions are not a "waste". API provided a detailed comment about this issue in the comments submitted for the proposed Subpart W revisions (Attachment B).
- **Subpart W must accommodate reporting emissions based on empirical data as a demonstration of emission reductions.** As required by CAA §136(h), Subpart W reporting (and by extension WEC calculations) must allow operators to submit empirical data "to accurately reflect the total methane emissions and waste emissions from the applicable facilities". The proposed Subpart W revisions do not allow operators to use readily available empirical data to show emission reductions and differentiate company performance (e.g., engine performance tests versus a static emission factor or control efficiency). See our detailed comments on the proposed Subpart W revisions (Attachment B).
- **EPA must set a period over which submitted GHG reports are considered "final" now that reported emissions will be used as a basis for the WEC.** The continual litany of questions from EPA to operators

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[7] EPA-HQ-OAR-2023-0234-0402, EPA-HQ-OAR-2023-0234-0403, and EPA-HQ-OAR-2023-0234-0404

years after Subpart W reports have been submitted must have a defined endpoint. Many queries are administrative in nature and do not lead to a significant change in emissions. EPA must establish a clear deadline for when emissions are validated and final. We provide more detail in Comment 6.0.

1.4 EPA has underestimated the impact of the WEC by basing its analysis on RY2021 Subpart W data.

EPA has underestimated the impact of the WEC by basing its analysis on RY2021 Subpart W data. This data underestimates the impact of the proposed WEC in two respects:

- RY2021 occurred during the COVID-19 pandemic and may not accurately reflect a typical year for oil and gas operations due to reduced energy demand.
- RY2021 (or any other year) data do not reflect the proposed Subpart W revisions which, based on the proposed Subpart W rule, will significantly increase reported methane emissions.

Given the unknown outcome of the final Subpart W revisions, the Industry Trades cannot fully assess the impact of the WEC. Given previous instances where EPA underestimated the impact of its rulemakings (e.g., storage vessels under NSPS OOOO). API believes that EPA has greatly underestimated the impact of the WEC, which also results in a failure to adequately assess impact to small businesses[8].

1.5 EPA must ensure regulatory harmonization and consistency.

In light of the volume of regulatory actions addressing methane, EPA should facilitate greater intra-agency coordination to ensure that EPA's regulations are internally consistent for their own purposes, and can serve as a basis for other agencies to harmonize their requirements with EPA's. These actions include, but are not limited to:

- Treasury Department – Section 45V regulations for hydrogen production tax credit, with the treatment of differentiated natural gas
- DOT/PHMSA – LDAR Rule
- DOI/BLM – Waste Prevention Rule
- DOE/Argonne – GREET Model, used as the basis for calculating GHGs associated with hydrogen production for eligibility for the Section 45V tax credit
- DOE – Differentiated Gas Framework
- State Department – International methane MRV standard (with DOE)
- State Department – Global discussions on an EU Import standard and global methane policy

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[8] Regulatory Flexibility Act

2.0 The Proposed Netting Provisions Are Unreasonably Constrained.

A key element of CAA § 136 is the ability of an owner or operator to net facility emissions "within and across all applicable segments" when determining whether fees must be paid and, if so, the amount of the fees. CAA § 136(f)(4) plainly was intended by Congress as a program flexibility that would reduce the fees paid under the WEC program. That clear Congressional intent would be better effectuated by a broadly applicable netting rule (i.e., one that allows netting among all facilities within the applicable segments under the common ownership of a parent company). EPA's proposed approach to netting is inconsistent with CAA § 136(f)(4) and would unreasonably constrain the opportunity for netting in two ways.

2.1 Netting should be allowed at the parent company level.

EPA proposes that the owner or operator that would be allowed to net among facilities would be "the Subpart W facility 'owner' or 'operator' as reported under 40 CFR 98.4(i)(3)."[9] EPA argues that approach "aligns with a plain reading of the statutory text" because "CAA section 136(c) requires the charge to be imposed and collected on a facility owner or operator, and CAA section 136(h) presumes that owners and operators are responsible for submitting empirical data."[10] EPA further argues that, "since the list of owners or operators for each facility is directly reported under 40 CFR 98.4(i)(3), an established program at the time that Congress drafted CAA section 136, the EPA proposes that under the best reading of the statutory text, the facility owner or operator would be used as the entity for establishing common ownership or control of subpart W facilities within and across all applicable subpart W industry segments."[11] EPA asks for comment on the alternative approach of using the parent company of a facility owner or operator, although that is not EPA's preferred approach.[12]

To begin, while Subpart W was indeed an "established program" at the time CAA § 136 was enacted, EPA must consider the fundamentally different purposes of CAA § 136 as compared to Subpart W in construing that section as a whole and the netting provisions in particular. The GHGRP and Subpart W were devised solely as an information gathering program. As such, the reporting mechanism – including identification of the relevant owner/operator for reporting purposes – was geared toward ease of information gathering and facilitating the collection of relevant and accurate information. In contrast, CAA § 136 is a fee program that has a wholly different purpose and effect than the GHGRP and Subpart W (e.g., creating an incentive for the reduction of methane emissions). More specifically, the netting provision clearly was intended by Congress as a way to incentivize methane emission reductions by reducing the WEC obligation. EPA thus has an obligation to take a fresh look at the term owner/operator under CAA § 136 to make sure the fee program regulations comport with the purposes of the program. From that perspective, allowing netting at the parent company level is appropriate because it would fully implement Congress's clear purpose of mitigating the impact of the fee program.

Moreover, EPA already correctly acknowledged that "for parent company [the highest level U.S. Parent company of owners (or operators)] reporting, the percent ownership in the facility is also reported under 40 CFR 98.3(c)(11). Because a parent company has an ownership interest in a subpart W facility multiple facilities may be said to be owned by the same parent company and might also be considered as being under common ownership or control of that parent company." While a subsidiary manages its own affairs and remains responsible for day-to-day operations, it is typically true that a parent company has sufficient investment oversight of the actions of its subsidiaries to reasonably have "ownership" or "control" solely for purposes of identifying the reporting entity

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[9] 89 Fed. Reg. at 5328

[10] *Id.*

[11] *Id.*

[12] *Id.*

under Part 98 and for netting under the WEC.[13]. Many parent companies file consolidated tax statements for their subsidiaries and have shared corporate functions. Furthermore, "control" of an entity should be considered for this purpose if the parent has at least a controlling shareholder interest, to be presumptively "under common ownership or control" of an affected facility. Also, capital investment decisions and resource allocation, as well as corporate strategies such as lower carbon initiatives, are generally done at the parent level. Netting at that level would allow for faster and more effective methane mitigation as parent companies will prioritize low-cost emissions reductions first across their entire portfolio.

More generally, EPA's assertion that its proposed approach reflects a "plain reading" of CAA § 136 is mistaken in any event. CAA § 136 allows for netting among applicable facilities under "***common*** ownership or control." CAA § 136(f)(4) (emphasis added). The term "common" naturally encompasses <u>all</u> operations within the ownership or control of a corporate entity. Nothing in CAA § 136(f)(4) suggests that the term "common" should be construed as being limited to operations owned/operated by the particular entity that reports under Subpart W, much less limited to a subsidiary of a larger corporate entity. Note that CAA § 136 requires emissions estimates under Subpart W to be used in implementing the WEC, but that does not mean that elements of Subpart W unrelated to quantifying emissions create any obligation or constraint under the WEC rule.

That is particularly true here, where the terms owner and operator under Part 98 were developed solely for the purpose of facilitating an information gathering regulatory program that is not governed by any specific CAA provision. As devised by EPA, netting is not a concept that has any meaning or relevance under Part 98 generally or Subpart W specifically. Thus, to give full effect to Congress's express direction to allow for netting under the WEC program among applicable facilities under common ownership or control, it is incumbent on EPA to construe those terms in the context of the WEC program and not limit the meaning of those terms to Part 98 rules that serve a wholly different purpose than the WEC program.

Moreover, the fact that the Subpart W approach to identifying the reporting entity predated CAA § 136 lends no additional support to EPA's proposed approach. That might have been true if CAA § 136 signaled some connection between the owner or operator for netting purposes and the owner or operator that reports under Subpart W. But Congress made no such connection between the two programs. Thus, the term "common ownership or control" in CAA § 136(f)(4) must be given its plain meaning.

EPA's proposed interpretation is therefore unfounded and unreasonable. The whole purpose of CAA § 136 is to identify what entities should pay a fee and to determine the amount of that fee. In proposing to define common ownership or control, EPA entirely fails to consider the effect of the various proposed methods of defining that term on the scope and extent of the fees that might be due under the program. Unless corrected (through further notice and comment rulemaking), that analytical failure will render the final rule arbitrary and capricious.

For these reasons, EPA's justification for the proposed netting provision is insufficient because the Agency failed to acknowledge, consider, and give full effect to the important role that Congress intended netting to play in mitigating the impact of the WEC program.

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[13] For the avoidance of doubt, a parent company may be deemed an owner or operator, or have control, of subsidiaries of facilities for purposes of GHG reporting and netting. However, this shall not be construed as indicating a parent company has direct ownership or operational responsibility for a particular facility or otherwise undermine the corporate separateness of a parent company and its subsidiaries that remain responsible for managing its day-to-day business and facility operation.

2.2 Facilities with less than 25,000 tpy GHG emissions should be allowed to net.

EPA proposes "that if a facility's emissions are not subject to the WEC, either because the facility is not a WEC applicable facility, or because a WEC applicable facility receives the regulatory compliance exemption, that facility's emissions do not factor into the netting of emissions for a WEC obligated party."[14] "In other words," EPA proposes that "only WEC applicable facilities may net, and only WEC applicable emissions may be netted."[15]

EPA explains that approach "is consistent with CAA section 136(f)(4) ''the Administrator shall allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds within and across all applicable segments identified in subsection (d),'' since the reference to ''applicable thresholds'' and ''applicable segments,'' which reflect other subsections under CAA section 136, implies that only WEC applicable emissions should be considered in the netting calculation."[16]

Limiting netting to only "WEC applicable facilities" is facially inconsistent with the plain text of CAA § 136(f)(4). The only relevant limiting provision in CAA § 136(f)(4) is the term "common ownership or control." Once common ownership or control is established, then the statute unambiguously allows netting of "facility emissions levels that are below the applicable thresholds within and across all applicable [industry] segments." Nothing in that language suggests or supports the limitation of netting only to "WEC applicable facilities."

EPA argues that facilities with less than 25,000 tons per year (tpy) of GHG emissions and facilities that qualify for the "regulatory compliance exemption" may not participate in netting because they are excluded from the program and, thus, cannot be considered "WEC applicable facilities."[17] But EPA's argument depends on its proposed definition of "WEC applicable facility" and not on the plain text of CAA § 136(f)(4). The proposed regulatory term "WEC applicable facility" describes facilities for which methane emissions must be determined and compared to the specified "waste emissions thresholds" – i.e., these are non-excluded facilities that are potentially liable for a waste emissions charge. While that proposed regulatory term may be useful in organizing the WEC regulations, that term is not prescribed by the statute and cannot be bootstrapped into a legal basis for imposing a constraint on netting that is not required by the statute.

The plain text of CAA § 136 dictates the proper outcome here. To begin, a facility with less than 25,000 tpy of GHG emissions plainly is an "applicable facility" because it is a "facility within [specified] industry segments, as defined in Subpart W."[18] That interpretation is reinforced by CAA § 136(c), which instructs that an "applicable facility that reports more than 25,000 metric tons" of GHGs may be required to pay a fee. That provision clearly connotes that a facility with less than 25,000 tons per year of GHG emissions still must be considered an "applicable facility."

Next, CAA § 136(f)(4) requires that "facilities under common ownership or control" must be allowed to net. The term "facilities" in that provision unambiguously is a reference to "applicable facilities," which as explained above, necessarily includes facilities with less than 25,000 tons per year of GHG emissions. Nothing in CAA § 136(f) reasonably suggests that the term "facilities" somehow can or should be construed as being limited only to what EPA proposes to define as "WEC applicable facilities" – i.e., those with GHG emissions greater than 25,000 tons per year and that have methane emissions less than the applicable waste emissions threshold.

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[14] 89 Fed. Reg. at 5329.
[15] *Id*.
[16] *Id*. at 5329-30.
[17] *Id.* at 5330-5332.
[18] CAA § 136(d).

Moreover, CAA § 136(f)(4) further provides that, for "facilities under common ownership or control," EPA must "allow for the netting of emissions by reducing the total obligation to account for facility emissions levels that are below the applicable thresholds." Nothing in that provision limits netting only to facilities required to determine whether their methane emissions exceed an applicable waste emissions threshold. Rather, that provision plainly requires EPA to allow owners or operators without limitation to "account for" all "facility emissions levels that are below the applicable thresholds" – including emissions from facilities with total GHG emissions below 25,000 tons per year.

The plain text of CAA § 136 thus must be interpreted to allow facilities with less than 25,000 tons per year of GHG emissions to participate in netting. We note that, if there were ambiguity in the statute (which there is not for the reasons just stated), it would be unreasonable and arbitrary to adopt the proposed prohibition on including facilities with less than 25,000 tons per year GHG emissions from participating in netting. As explained above, CAA § 136(f)(4) plainly was intended by Congress as a program flexibility that would reduce the fees paid under the WEC program. That clear Congressional intent would be better effectuated by a broadly applicable netting rule (i.e., one that allowed applicable facilities with less than 25,000 tons per year of GHG emissions to participate in netting). As above, EPA's justification for this aspect of the proposed netting provision is insufficient because the Agency failed to acknowledge, consider, and give full effect to the important role that Congress intended netting to play in mitigating the impact of the WEC program.

EPA's proposed approach also would reduce a powerful incentive to reduce methane emissions. As proposed, within the context of the WEC once an applicable facility reduces its emissions to less than 25,000 tons per year, there is no incentive to accomplish further emissions reductions because additional reductions have no value under the Proposed Rule. If such facilities were allowed to participate in netting, further emissions reductions would be strongly incentivized because such reductions could be used in netting. At a minimum, an EPA failure to fully consider the practical implications of its proposed approach – including the incentives described here – would render this aspect of the final rule arbitrary and capricious.

3.0 The Proposed Unreasonable Delay Exemption Criteria Are Unduly Restrictive.

CAA § 136(f)(5) provides explicit exemption from the fee if emissions are caused by "unreasonable delay, as determined by the Administrator, in environmental permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation."

To implement the above statute, EPA proposes the following four criteria to govern implementation of that exemption: (1) "the facility must have emissions that exceed the waste emissions threshold; (2) neither the entity seeking the exemption, nor the entity responsible for seeking the permit, may have contributed to the delay; (3) the exempted emissions must be those (and only those) resulting from the flaring of gas that would have been mitigated without the permit delay, and the flaring that occurs must be in compliance with all applicable local, state, and Federal regulations regarding flaring emissions; and (4) a set period of months must have passed from the time a submitted permit application was determined to be complete by the applicable permitting authority."[19]

EPA's proposed criteria for implementing the unreasonable delay exemption are unduly restrictive given the various environmental permits required for oil and natural gas infrastructure. The unreasonable delay exemption

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[19] 89 FR 5332-5333

should provide maximum relief to operators when federal, state, or local agencies fail to issue permits in a timely fashion.

3.1 EPA should adopt a case-by-case process for determining whether an unreasonable delay in permitting has occurred.

Rather than limiting the unreasonable delay exemption by inappropriate and impractical brightline criteria, EPA should adopt a case-by-case process for determining whether an unreasonable delay in permitting has occurred. At a minimum, this case-by-case process should be an alternative to EPA's proposed criteria. Set timelines for applicant responsiveness and unreasonable delay for permit issuance do not recognize the complexity of environmental permitting for gathering and transmission infrastructure. A single pipeline project may require several environmental permits from various federal, state, and local agencies with different application procedures and review timelines. For example, a natural gas pipeline project may require the following federal, state, and local permits:

- Certificate of Public Convenience and Necessity from Federal Energy Regulatory Commission (FERC),
- Section 404 General Permit from the Army Corps of Engineers,
- Section 7 Threatened and Endangered Species Clearance from the Fish and Wildlife Service (FWS),
- Water and air permits from the state environmental agency, and
- Erosion and Sedimentation Control Plan Review from the County Conservation District.

The various permitting actions may occur in parallel or in sequence. An unreasonable delay for a prerequisite permit would delay a project even if subsequent permits are issued in a timely fashion. For example, a compressor station in Texas may require separate construction (i.e. New Source Review (NSR)) and operating (i.e. Title V) air permits; the Title V permit cannot be issued until the NSR permit authorization is approved.

Furthermore, environmental permitting for gathering and transmission infrastructure occurs on various spatial scales. An unreasonable delay in environmental permitting for a pipeline mainline could affect hundreds to thousands of production sites in a basin while a delay for a connecting line would impact one to a handful of sites.

Given the complexity in the environmental permitting for gathering and transmission infrastructure, EPA should allow companies to apply for a case-by-case exemption for methane emissions for an individual site up to an entire basin resulting from an unreasonable delay in permitting. Our comments on EPA's proposed brightline criteria for applicant responsiveness and an unreasonable delay for permit issuance by the agency are below.

3.1.1 The proposed brightline criteria for contribution to the delay are inappropriate and impractical.

EPA explains that contribution to the delay "would be determined based upon the timeliness of response to requests for additional information or modification of the permit application. Delays in response exceeding the response time requested by the permitting agency, or requested by the relevant production or gathering or transmission infrastructure entity seeking the permit, or responses that exceed 30 days from the request if no specific response time is requested, would be considered to contribute to the delay in processing the permit application."[20]

Such brightline rules are not appropriate because they do not reflect the actual ebb and flow of permitting actions. For example, if a permitting authority imposes an unreasonably short deadline for submitting supplemental information, the applicant will become ineligible for the exemption notwithstanding otherwise prompt and complete submission of the needed information. Similarly, a fixed 30-day default deadline ignores the likely possibility that, even with the best efforts by the applicant, certain additional information submissions will unavoidably take longer than 30 days to compile. EPA should allow for a subjective assessment in such cases rather than imposing brightline criteria.

Furthermore, the entity seeking the exemption does not have knowledge of or control over whether the entity seeking the permit has contributed to the delay in the case that the entity seeking the exemption and the entity seeking the permit are under different parent companies. For this case, the lack of knowledge or control makes this criterion impractical to implement for the entity seeking the exemption. Also, in the case of a large pipeline project, unresponsiveness from the entity seeking the permit would unfairly disqualify several other entities from this exemption through no fault of their own.

3.1.2 The proposed brightline criteria for defining unreasonable delay do not reflect different permit issuance timelines for various agencies.

EPA suggests that an appropriate "set period of months" to assess unreasonable delay should be 30 to 42 months[21]. Again, such brightline criteria could unfairly cause an applicant to become ineligible for the exemption in situations where faster action by the permitting authority should be expected. Reasonable permit issuance timelines vary by agency and by permit type. For example, the Texas Commission on Environmental Quality (TCEQ) has published target permit issuance time frames[22] for air permits ranging from 45 days for the simplest authorizations to 12 months for the more complex permits. API notes that these timeframes are much less than EPA's proposed range but also recognizes that longer time frames are expected for other agencies and permits.

Another example is the Right-of-Way (ROW) process for the Bureau of Land Management (BLM). A ROW is required for every project built on public land including each connecting line to an existing gathering pipeline or electrical transmission line. After an initial evaluation, BLM notifies the applicant on whether the application can be processed within 60 days. Considering this goal timeline, an unreasonable delay in ROW permitting would likely not be 30 to 42 months but would still result in methane emissions from flaring (where otherwise allowed), generator engines, and other activities due to that delay.

As above, EPA should provide leeway for the assessment and application of situation-specific facts and circumstances. Therefore, EPA should adopt a case-by-case process for determining whether an unreasonable delay in permitting has occurred.

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[20] 89 FR 5332

[21] 89 FR 5334

[22] TCEQ - Factsheet - Air (APD-ID 32v1.0, Revised 06/21). https://www.tceq.texas.gov/assets/public/permitting/air/factsheets/permit-factsheet.pdf Accessed February 22, 2024.

3.2 EPA unduly restricts exempted emissions to those from flared gas which are not the only emissions resulting from unreasonable delay in environmental permitting for gathering and transmission infrastructure.

Rather than limiting exempted emissions to flaring, EPA should allow operators to determine the methane emissions that result from an unreasonable delay in environmental permitting for gathering and transmission infrastructure. These exempted emissions would be determined on an individual site basis and then totaled and subtracted from the emissions on WEC applicable facility basis. Some examples of additional exempted methane emissions include, but are not limited, to the other compliance options under OOOObc for associated gas:

- **Use of gas as an onsite fuel source.** While API believes that combustion emissions should be included under Subpart C or at least exempted from the WEC, onsite combustion emissions that result from an unreasonable delay should be exempted.
- **Use of gas for a useful purpose that a purchased fuel or raw material would serve.** If an operator implements a process onsite to use the gas due to an unreasonable delay, those methane emissions should be exempted.
- **Use of gas for reinjection into the well or injection into another well.** An operator may choose to inject or reinject the gas rather than flare due to an unreasonable delay. All methane emissions associated with the injection process (e.g., combustion from compressor driver, reciprocating or centrifugal compressor, fugitive emissions components, etc.) should be exempted.

While the above options focus on methane emissions resulting from an unreasonable delay for gas infrastructure, methane emissions from storage vessels could also be caused by an unreasonable delay for liquid infrastructure. EPA should also allow operators to exempt emissions from generator engines due to an unreasonable delay for electrical transmission; generator engines were considered acceptable by EPA to power instrument air skids for OOOObc compliance for process controllers and pumps. Operators should have the maximum flexibility to determine which methane emissions are the result of an unreasonable delay and therefore should be exempt from the WEC.

3.3 EPA must clarify "in compliance with all applicable local, state and federal regulations regarding flaring emissions".

One of the proposed criteria for the unreasonable delay exemption is "[reported flaring emissions] are in compliance with all applicable local, state and federal regulations regarding flaring emissions". This criterion should be clarified in several ways.

- **"All applicable local, state and federal regulations regarding flaring emissions" should be limited to environmental regulations.** While the phrase "regarding flaring emissions" implies that the criterion is limited to environmental regulations, other agencies (e.g., state oil and gas commissions) also have regulations regarding flaring. To avoid potential confusion, EPA should clearly state that only applicable local, state and federal environmental regulations are relevant for the purposes of the unreasonable delay exemption.
- **"Compliance" means no proven or admitted violations to applicable environmental regulations.** EPA must specify that only violations that are proven through an adjudication or to which an entity admits liability would disqualify flaring emissions (or other potentially exempt emissions – see comment above) from this exemption. Also, refer to Comment 4.0 under the regulatory compliance exemption.

- **Facilities should not be subject to liability or interest if EPA or another environmental regulatory authority determines after the fact that violations existed.** Liability for potential violations is often not determined until well after the underlying event occurred. The time necessary to resolve enforcement actions should not result in interest charges because such interest charges would penalize entities for exercising their right against alleged violations. Also, refer to Comment 4.0 under the regulatory compliance exemption.

3.4 EPA must clearly define a "complete environmental permit application" as an administratively complete application.

Various environmental permitting agencies have different definitions and levels of completeness regarding permit applications. Typically, the first and simplest level of completeness is administratively complete, which means the application contains the required forms and supporting information for the agency to conduct a more detailed technical review. The submittal of additional or revised information during technical review does not make an environmental permit application administratively incomplete but is a typical and expected part of the agency review process. If EPA chooses to implement a set period of months to assess unreasonable delay, the clock should start after the application is deemed administratively complete by the appropriate permitting authority. Defining a "complete environmental permit application" as a technically complete application would unreasonably restrict the scope of this exemption and make it virtually meaningless.

3.5 Reporting and recordkeeping requirements associated with the unreasonable delay exemption should be streamlined.

Reporting and recordkeeping requirements associated with the unreasonable delay exemption should be limited to only those items necessary to verify that the exemption is met. While API recognizes that a case-by-case process may require more detailed information, EPA should make the reporting and recordkeeping requirements clear and fit-for-purpose. API has the following specific comments on the proposed reporting and recordkeeping requirements for the unreasonable delay exemption.

- **The attestation of responsiveness for the entity seeking the permit as proposed in § 99.31(b)(4) cannot reasonably be made by the entity seeking the exemption if it is a different entity.** The entity seeking the exemption does not have control or knowledge of the responsiveness of the entity seeking the permit in the case where the entity seeking the exemption and the entity seeking the permit are under different parent companies. Attestations should only be made for actions under the control of the entity making that attestation.

- **As proposed in § 99.31(b)(5)(ii), reporting *"[a] listing of methane emissions mitigation activities that are impacted by the unreasonable permitting delay"* is meaningful only if the scope of exempted emissions is expanded beyond flaring emissions.** Otherwise, operators will always report "sending natural gas to sales instead of flare" as the methane emissions mitigation activities. If EPA expands the scope of exempted emissions, operator should be able to simply identify the activities and associated methane emissions that were exempted.

- **The information proposed in §99.31(b)(10) should be limited to a certification statement only.** Specifically, *"Information on all applicable local, state, and federal regulations regarding flaring emissions and the facility's compliance status for each"* should be simplified to a certification that flaring complied will all applicable local, state, and federal environmental regulations regarding flaring emissions. EPA should not require detailed compliance information, such as annual reports, to determine eligibility for an exemption. Also, the compliance certification should be limited to environmental regulations only.

- **Records regarding the permit application should only be required for the entity seeking the permit.** The recordkeeping requirements proposed in 99.33(a) should clearly state that these records need only be kept by the entity seeking the permit.

- **EPA should only require the information on the permit application necessary to determine if an unreasonable delay has occurred.** As proposed in 99.33(a)(3), EPA is requiring "Information on whether the facility's response included modification to the permit application." This information is not necessary to determine if the exemption applies and implies that a technical update to the permit application would make the permit application "incomplete". As discussed above, a complete environmental application should be an administratively complete application. Technical updates to permit application are routinely submitted during the review process and do not necessarily "restart the clock" on determining if an unreasonable delay has occurred.

4.0 The Proposed "Regulatory Compliance Exemption" Unreasonably Limits the Scope of That Exemption.

CAA § 136(f)(6) provides an exemption from paying fees for applicable facilities that are "subject to and in compliance with methane emissions requirements pursuant to [CAA §§ 111(b) and (d)]" provided that "methane emissions standards and plans pursuant to [CAA §§ 111(b) and (d)] have been approved and are in effect in all States with respect to the applicable facilities" and compliance with those programs "will result in equivalent or greater emissions reductions as would be achieved by" the 2021 OOOObc proposed rule.

EPA proposes detailed rules for administering CAA § 136(f)(6).[23] As detailed below, several elements of those proposed rules are inconsistent with the statute or otherwise unreasonable.

4.1 An applicable facility should be eligible for the regulatory compliance exemption as soon as a state or federal program is approved and in effect for the state(s) in which that facility is located.

EPA proposes that the regulatory compliance exemption will become available only after "***all*** state and Federal plans pursuant to CAA section 111(d) are approved and in effect."[24] (emphasis added). More specifically, EPA "proposes to interpret ''all states'' in CAA section 136(f)(6)(A)(i) to mean that every state with an applicable facility (i.e., all states with Subpart W facilities containing CAA section 111(b) or (d) facilities) must have an approved plan (state or Federal) before" the exemption becomes available for any applicable facility.

That "all or nothing" approach is inconsistent with CAA § 136 and unreasonably limits availability of the exemption. CAA § 136 specifies that programs must be "approved" and "in effect in all States with respect to the applicable facilities."[25] The use of the plural in that provision does not compel EPA's "all or nothing" approach. Instead, the term "facilities" plainly is a reference back to the term "affected facility" in subsection (f)(6)(A). As

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[23] 89 Fed. Reg. at 5336-47.
[24] *Id*. at 5337
[25] CAA § 136(f)(6)(A)(i).

such, the law provides that applicability of the exemption should be determined on a facility-by-facility basis and that a facility should qualify as long as programs are "approved and in effect" for that particular facility. The use of the plural simply accommodates the possibility that a given facility might straddle a state line.

Moreover, the "all or nothing approach" unreasonably limits the availability of the exemption based on circumstances beyond the control of affected facilities and of states that promptly enact and obtain approval for their programs. It thus creates a perverse incentive for states to slow the implementation of their programs if it is apparent that other states are moving on a much slower timeline.[26]

Moreover, the "all or nothing approach" does nothing to incentivize the prompt development and approval of state programs by proactive states because such states would not realize any benefits for their regulated communities from the regulatory compliance exemption if they act early because implementation of the exemption would be held back by the lagging states. And, it would have the perverse effect of disallowing the exemption from continuing to apply anywhere in the Nation if a single approved state program anywhere in the Nation loses its EPA approval (e.g., through a successful legal challenge to EPA's approval in the litigation that inevitably will occur over EPA's approval decisions). Thus, EPA's proposed approach would make compliance planning virtually impossible and frustrate any settled expectations that come with program approval.

More generally, EPA's proposed approach also would infringe on the cooperative federalism that is a key feature of CAA § 111(d). That provision unambiguously requires EPA to implement the existing source program through a SIP-like program, where EPA provides the overarching program structure and each state develops and imposes the source specific emissions limitations and standards for the state. The "all or nothing" proposed approach to implementing the regulatory compliance exemption would unreasonably tie the states together in a way that prevents states from determining its own fate, as CAA § 111(d) clearly requires.

4.2 The regulatory compliance exemption should become available as soon as an applicable state or federal plan is in effect.

EPA "proposes that the exemption should become available as soon as all state or federal plans are ***in effect***, because facilities can be in compliance with the requirements in [a] plan even if full implementation of those requirements is not required until a future date."[27] (emphasis added). In other words, once an approved CAA § 111(d) program become effective, affected facilities subject to that program become eligible for the exemption even if emissions control requirements do not become applicable until later dates.

API supports such an approach. We agree with EPA's rationale. But we note that that approach is particularly appropriate because the statute unambiguously requires it.[28] The words "in effect" plainly refer to EPA's CAA § 111(b) new source regulations and state CAA § 111(d) existing source programs and not to the discrete components of those regulations and programs. As EPA aptly explains, that stands to reason because "It is [] possible for CAA section 111(d) facilities to be in compliance with the methane emissions requirements in a plan even if not all compliance dates included in the plan have come to pass."

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[26] We note that EPA assumes in the RIA that the regulatory compliance exemption will become available in 2027. That is an unreasonable and unfounded assumption – especially in light of the proposed "all or nothing" approach, which virtually guarantees that the exemption will not be available that early.

[27] 89 Fed. Reg. at 5338

[28] See CAA § 136(f)(6)(A)(i) (the regulatory compliance exemption becomes available when relevant "standards and plans pursuant to subsections (b) and (d) of [CAA § 111] have been approved and are ***in effect*** ….") (emphasis added).

4.3 API opposes the "all or nothing" approach to implementing the regulatory compliance exemption but supports EPA's rationale for a national equivalency evaluation if EPA implements the "all or nothing" approach.

EPA proposes that "a national evaluation is the most appropriate geographic scale for the purposes of the equivalency determination" with the 2021 proposed OOOObc.[29] EPA argues that "[b}ecause the climate impacts of these emissions are dependent on their aggregate quantity rather than where they occur, a national-level evaluation will provide an appropriate comparison of the overall impact of the reductions that would have been achieved under the NSPS OOOOb/EG OOOOc 2021 Proposal and those that will be achieved upon implementation of the final NSPS OOOOb and state and Federal plans implementing OOOOc."[30]

As explained in subsection A above, API opposes EPA's proposed "all or nothing" approach to implementing the regulatory compliance exemption. However, we agree with EPA's assertion that the potential "climate impacts" of GHG emissions "are dependent on their aggregate quantity rather than where they occur."[31] In other words, local GHG emissions reductions do not directly alleviate any potential climate-related local public health or air quality impacts related to those emissions because aggregate global GHG emissions produce largely homogenous global atmospheric concentrations of GHGs. Thus, any potential "climate impacts" attributable to anthropogenic GHG emissions at any particular location are a product of global activity and global atmospheric conditions.

4.4 The fact that a state plan properly employs "RULOF" to derive alternative emissions standards that are less stringent than EPA's proposed emissions guidelines does not make that plan less stringent than EPA's 2021 proposed rule.

EPA proposes that "the inclusion of the NSPS OOOOb/EG OOOOc 2021 Proposal as the baseline for the equivalency demonstration to mean that Congress intended for the EPA to assume, for purposes of [the state equivalency] analysis, that the proposed standards were finalized as drafted in the NSPS OOOOb/EG OOOOc 2021 Proposal and implemented nationwide."[32] EPA observes that "it is possible that some states may [] set different standards of performance than the presumptive standards proposed in EG OOOOc based on a provision of CAA section 111(d)(1) permitting states to ''take into consideration, among other factors, the remaining useful life of a source.'' (The EPA refers to this provision as the ''remaining useful life and other factors'' provision, or RULOF.)"[33]

According to EPA, "In such circumstances, the emissions reductions achieved by those state plans would have been less than if the state plans had adopted and implemented the presumptive standards in the final emissions guidelines, had they been finalized."[34] But EPA asserts that "because state plans were never developed pursuant to the NSPS OOOOb/EG OOOOc 2021 Proposal, there is no means of reasonably estimating the requirements that may have been included in those state plans and what emissions reductions they would have achieved."[35] EPA thus proposes that it will not consider the possibility of RULOF-based state standards in determining the baseline program effectiveness to be used in making program equivalency determinations. EPA argues that approach "is aligned with a plain reading of CAA section 136(f)(6)(A)."[36]

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[29] Notice at 5341.
[30] *Id.*
[31] *Id.*
[32] *Id. at 5341.*
[33] *Id. at 5342.*
[34] *Id.*
[35] *Id.*
[36] *Id. at 5341.*

The effect of EPA's proposed approach is to cause any state plan containing RULOF-based emissions limitations or standards that are "less stringent" than the corresponding emissions guidelines in the 2021 proposal to be less stringent than the 2021 proposal, unless the state otherwise imposes sufficiently more stringent emissions limitation or standards on other sources to make up the difference. If EPA adopts a state-by-state approach to making equivalency determinations (as it must for the reasons explained above), that means that no state plan containing RULOF-based emissions limitations or standards could be determined by EPA to provide equivalent emissions reductions as the 2021 proposal unless the state achieves greater than needed emissions reductions in other ways.

EPA's proposal is flawed for two reasons. First, as API explained in its comments on the 2021 Proposal, that proposal is not a legally cognizable proposed rule because it did not contain and otherwise was not accompanied by proposed regulatory text.[37] Consequently, in construing and applying CAA § 136(f)(6)(A)(ii), ***any*** state plan will "result in equivalent or greater emissions reductions as would be achieved by [the 2021] proposed rule" because that proposed rule did not propose legally cognizable emissions limitations or standards that could possibly have resulted in emissions reductions. Thus, inclusion of RULOF-based emissions limitations or standards in a state plan would not cause that state plan to produce fewer emissions reductions than strict adherence to the 2021 "proposed rule."

Second, the 2021 proposed rule acknowledged and accommodated the possibility of less stringent state standards based on consideration of RULOF.[38] Indeed, EPA could do no less because, as EPA states, "the statute requires" states to have that authority. [39]

Thus, the possibility of less stringent RULOF-based state standards ***was*** incorporated into the 2021 proposed rule. As a result, EPA cannot reasonably conclude that the baseline for equivalency determinations cannot include the possibility of RULOF-based standards. A plan with adequately justified RULOF-based standards necessarily would achieve at least as much emissions reductions as the 2021 proposal would require because such standards were embraced (as EPA legally must) in that proposal.

4.5 EPA must consider the overall emissions reductions achieved by state plans and not just those emissions reductions that would be achieved by the sources addressed in the 2021 proposed rule.

We note that the 2021 proposal did not include at least one source type covered by the 2022 supplemental proposal.[40] Moreover, the 2022 supplemental proposal provides regulatory details about certain provisions that were addressed only in concept in the 2021 proposal.[41] Such conceptual elements of the 2021 proposal do not constitute and cannot reasonably be construed as constituting a proposed emissions limitation or standard for purposes of making equivalency determinations under CAA § 136(f)(6)(A)(ii).

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[37] Letter from Frank J. Macchiarola to The Honorable Michael S. Regan (Jan. 31, 2022) (docketed at EPA-OAR-2021-0317-0808) at 55.

[38] 86 Fed. Reg. 63110, 63251 (Nov. 15, 2021) ("To the extent that a State determines the presumptive standards in the final EG are not reasonable for a particular designated facility due to remaining useful life and other factors, the statute requires that the EPA's regulations under CAA section 111(d) permit States to consider such factors in applying a standard of performance.").

[39] CAA § 111(d)(1).

[40] 87 Fed. Reg. 74702, 74707 (Dec. 6, 2022) ("[T]he EPA is proposing methane and VOC standards for one new emission source that is currently unregulated (i.e., dry seal centrifugal compressors).")

[41] See, e.g., 86 Fed. Reg. at 63177 (Where EPA asked for comment on a concept, but not an actual proposed rule, "on how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event.").

As a result, the 2022 supplemental proposal would regulate additional source types and activities than the 2021 proposal. Moreover, as long as they are consistent with CAA § 111 standard setting criteria, states have further latitude to regulate source types and activities in their CAA § 111(d) existing source programs than EPA nominally would regulate under its emissions guidelines.

CAA § 136(f)(6)(A)(ii) requires equivalency determinations to consider the emissions reductions that would be achieved by approved state CAA § 111(d) plans versus reductions that would have been achieved under the 2021 proposed rule. Thus, EPA must make it clear in the final rule that the overall emissions reductions achieved by state plans must be considered in making equivalency determinations and not just the emissions reductions that would be achieved by the program elements proposed in 2021.

4.6 A proven or admitted violation should disqualify only the Subpart OOOO/a/b/c affected or designated facility from the regulatory compliance exemption.

EPA proposes "to interpret and implement the regulatory compliance exemption such that an applicable Subpart W facility that contains any CAA section 111(b) or (d) facilities would be eligible for the exemption once all other criteria are met."[42] Under that interpretation, an entire applicable facility becomes ineligible for the regulatory compliance exemption when a violation is proven or admitted, even when the violation involves only a subset of the equipment or operations at the facility. The Industry Trades object to that "all or nothing" approach.

Instead, if a violation is proven or admitted, the regulatory compliance exemption should be disallowed only for the particular Subpart OOOO, OOOOa, OOOOb, or OOOOc applicable or designated facility that is in violation. For example, under Subpart OOOOa, the pneumatic controller applicable facility is each individual pneumatic controller.[43] Thus, if a particular pneumatic controller is determined or admitted to be out of compliance with Subpart OOOOa requirements, only that controller should be excluded from the regulatory compliance exemption. The remainder of the applicable facility should continue to qualify for the exemption.

That approach comports with CAA § 136(f)(6)(A) because the term "compliance" necessarily only applies to the parts of applicable facilities that are subject to Subpart OOOO requirements. Moreover, because the Subpart OOOO rules apply to discrete applicable or designated facilities, it is not reasonable or sensible to extend the consequences of a proven or admitted violation to equipment or operations beyond the applicable or designated facility that is in violation.

Also, EPA's approach will, as a practical matter, deprive the regulatory compliance exemption of its intended effect because even a single violation at a single piece of equipment would make the entire applicable facility (as proposed, "applicable facility" in this instance meaning the entire Subpart W reporting basin, which compounds the issue as such a "facility" would substantially expand the number of sites with OOOObc "affected facilities") ineligible for the exemption for an entire year. While owners and operators strive for 100% compliance, perfection often is unattainable – especially given the nature of the Subpart OOOO rules, which result in hundreds of thousands of discrete compliance obligations for even modest sized facilities in any given year. In short, EPA's proposed approach would render the regulatory compliance exemption a near nullity under the WEC program, which is wholly inconsistent with Congress's clear intention that the exemption should provide a practical and

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[42] 89 Fed. Reg. at 5343.
[43] 40 C.F.R. § 60.5390.

meaningful way to avoid paying fees under the WEC while still achieving the methane emissions reductions the WEC otherwise would incentivize.

Lastly, EPA states that "[f]or the purpose of determining WEC facility eligibility for the regulatory compliance exemption, the EPA proposes that the compliance status of CAA section 111(b) and (d) facilities contained within a WEC applicable facility would be assessed based on compliance with the applicable methane emissions requirements for the Oil & Natural Gas Source Category (40 CFR part 60, Subparts OOOOa, OOOOb, and OOOOc)."[44] API supports that interpretation. Indeed, the reference to "methane emissions requirements" in CAA § 136(f)(6)(A) unambiguously is a reference to standards applicable to sources in the oil and natural gas sector, which Congress understood to be prescribed by the NSPS OOOO series of rules. Thus, no other interpretation is permissible.

4.7 An applicable facility should be considered "in compliance" with methane emissions standards unless a violation is proven through adjudication, or the violation is admitted by the owner or operator of the affected facility.

"The EPA is proposing that a WEC applicable facility would not be eligible for the regulatory compliance exemption if any CAA section 111(b) or (d) affected facility that is contained within the WEC applicable facility has one or more deviations or one or more violations of any methane emissions requirement under the applicable NSPS or state or Federal plan issued pursuant to the EG."[45] That element of the Proposed Rule is flawed for two reasons.

First, it would apply to "deviations," which is a term that does not necessarily connote a violation of applicable requirements. For example, EPA's Part 71 federal Title V permitting rules unambiguously provide that "[a] deviation is not always a violation."[46] Thus, "deviations" should not be covered by the rule and should not constitute a disqualifying event. Under the oil and gas NSPS specifically, the fact that there is an established process to report deviations is an indication that EPA understands and expects there to be deviations from the rule. Therefore, penalizing self-reporting seems counterproductive.

Second, in the Proposed Rule, EPA assumes without analysis or explanation that the owner or operator of an applicable facility has the burden of affirmatively certifying that the facility is "in compliance" in order to qualify for the regulatory compliance exemption. That assumption in itself is a flaw in the Proposed Rule because the burden of proof is a key legal aspect of the regulatory compliance exemption and, thus, EPA has an obligation to explain the legal, policy, and factual bases for its proposed interpretation.

But more importantly, a cornerstone of our legal system is that a person is considered innocent until proven guilty. That is reflected in the Agency's well-established enforcement practices, where a "notice of violation" or "finding of violation," which typically marks the start of a formal civil enforcement action, represents a mere allegation of a violation and is not a legally binding definitive finding of violation. Such a definitive determination of noncompliance may be achieved only through adjudication or by admission of the liable party.

Here, the term "deviation" again becomes relevant. For example, under the Title V operating permit program, each permittee is required to submit an annual compliance certification with the terms and conditions of the

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[44] *Id*. at 5344.
[45] *Id*. at 5344, bottom right.
[46] 40 C.F.R. § 71.6(a)(3)(iii)(C).

permit.[47] But that requirement specifically requires that the certification "shall identify each ***deviation*** and take it into account in the compliance certification."[48] (emphasis added). Thus, the annual compliance certification does not require certification of "violations." Instead, it requires certification against potential "deviations," which may or may not constitute a violation. The term "deviation" was intentionally used in that provision to prevent a Constitutionally unsound interpretation that would require affected sources to certify to the existence of violations which, given the potential criminal liability that might arise due to noncompliance with Title V requirements, would unlawfully require responsible officials to incriminate themselves.

Thus, the burden of proof of noncompliance rests with the government (or others authorized to enforce CAA applicable requirements).[49] Applied here, that means that the owner or operator of an applicable facility should be considered to be "in compliance" for purposes of the regulatory compliance exemption unless, for the given reporting year, a violation of applicable NSPS OOOO/a/b/c requirements is determined through adjudication or admission by the owner or operator of the applicable facility.

We note that EPA proposes to require applicable facilities seeking to qualify for the regulatory compliance exemption to submit a compliance certification as part of their application for the exemption.[50] For the reasons explained above, that requirement should not be finalized.

4.8 The proposed scope of compliance determinations is unreasonably broad and unworkable.

According to EPA, "there are many potential elements to compliance with the methane requirements promulgated under CAA sections 111(b) and (d), such as compliance with a quantitative emissions limit and compliance with work practice standards, as well as multiple monitoring, recordkeeping, and reporting requirements."[51] EPA proposes that "a deviation or violation from any of the methane requirements promulgated under CAA sections 111(b) and (d) constitutes non- compliance for purposes of the regulatory compliance exemption."[52] This element of the proposal is flawed for two reasons.

First, CAA § 136(f)(6)(A) specifies that applicable facilities must be in compliance with "methane emissions requirements." The subsequent subparagraph uses the term "methane emissions standards."[53] Those terms should be interpreted in concert to mean just the parts of the OOOObc rules that limit emissions, and not the additional administrative requirements that accompany the emissions standards. Indeed, the term "emission standard" is defined at CAA § 302(k) to mean "a requirement … which limits the quantity, rate, or concentration of emissions of air pollutants." Under that definition, the term "methane emissions standard" must be interpreted to apply only to emissions reduction measures. As EPA itself emphasizes, the purpose of the regulatory compliance exclusion is to encourage emissions reductions. Thus, eligibility for the exclusion should depend only on compliance with requirements that actually result in emissions reductions.

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[47] *Id.* at § 70.6(c)(5).

[48] *Id.* at § 70.6(c)(5)(iii)(C)

[49] That is particularly true here because CAA § 136 does not impose an obligation on owners/operators to demonstrate compliance, which stands in sharp contrast to other CAA provisions where such an obligation is expressly imposed. See, e.g., CAA § 114(a)(3) ("The Administrator shall in the case of any person which is the owner or operator of a major stationary source, and may, in the case of any other person, require enhanced monitoring and submission of compliance certifications.").

[50] 89 Fed. Reg. at 5346

[51] *Id.* at 5345.

[52] *Id.*

[53] *Id.* at § 136(f)(6)(A)

Second, EPA should exclude violations that do not result in any excess emissions. Again, the whole point of the exemption is to encourage and incentivize emissions reductions. Violations that do not result in any excess emissions that stand to materially impede program effectiveness do not compromise that goal of the exemption. Moreover, excluding such violations will make implementation of the exclusion more manageable and predictable.

More broadly, consistent with our comments above for the proposed netting provision, the "regulatory compliance exemption" was plainly intended by Congress to be a program flexibility that would reduce the fees paid under the WEC program. That clear Congressional intent would be better effectuated by broadly applicable rules for implementing the regulatory compliance exemption rather than the highly constrained approach that EPA proposes here. EPA's justification for the proposed rules for implementing the regulatory compliance exemption is insufficient because the Agency failed to acknowledge, consider, and give full effect to the important role that Congress intended that exemption to play in mitigating the impact of the WEC program.

Lastly, the "regulatory compliance exemption" is an exemption from paying fees and not an exemption from the WEC program. Thus, any proven or admitted noncompliance should preclude application of the exemption only for the period that the noncompliance exists. Thus, if a noncomplying event lasts for just one day, the exemption should be available for the remaining days of the reporting year. For the part of the year that the exemption is not applicable (in this example, for the one day), the owner or operator of the applicable facility should be required to pay a fee if emissions during that period exceed the applicable waste emissions threshold.

4.9 An owner or operator that does not claim the regulatory compliance exemption should not be required to report information that would otherwise be required to confirm the applicability of the exemption.

The Proposed Rule at § 99.42(d) appears to require an owner or operator to submit information related to implementation of the regulatory compliance exemption even in cases where the owner or operator does not seek to claim the exemption. For obvious reasons, that reporting requirement should be revised to apply only to those seeking to claim the exemption. For example, it appears that all facilities must prepare and report compliance certifications for all applicable facilities – including those for which the regulatory compliance exemption is not claimed. Because compliance certifications are not needed for any purpose under the WEC except to demonstrate eligibility for the regulatory compliance exclusion, the requirement to prepare and submit certifications should not extend beyond facilities for which the exemption is sought.

We note that EPA itself emphasizes that "[w]here a WEC obligated party represents that each CAA section 111(b) and (d) facility is in compliance, but the EPA or another regulatory authority subsequently discovers the existence of one or more deviations or violations, or the CAA section 111(b) and (d) facility identifies the deviation or violation as a result of an EPA investigation (including information requests), the WEC obligated party may be subject to enforcement and required to pay any outstanding fees and interest penalties."[54] More importantly, EPA emphasizes that "[f]alse statements may be subject to criminal enforcement."[55] Thus, imposing an unneeded and unwarranted broadly-applicable compliance certification obligation also would unreasonably expose owners/operators to enforcement liability.

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[54] 89 FR at 5346.

[55] *Id.*

5.0 Exemption for Permanently Shut-in and Plugged Wells

CAA § 136(f)(7) provides that "[c]harges shall not be imposed with respect to the emissions rate from any well that has been permanently shut-in and plugged in the previous year in accordance with all applicable closure requirements, as determined by the Administrator." The EPA proposes that "the methane emissions eligible for the exemption are those that occur at the well level including those from wellhead equipment leaks, liquids unloading, and workovers with and without hydraulic fracturing in the reporting year in which the well was plugged."[56]

5.1 EPA should expand the methane emissions eligible for the exemption to all methane emissions from all equipment and processes that were associated with the permanently shut-in and plugged well.

EPA's proposal for implementing the exemption for emissions from plugged wells does not fully implement the statute since EPA is choosing to limit emissions from the wellhead and associated activities only. EPA should not limit the emissions eligible for the exemption to just those "that occur at the well level." Instead, EPA should implement the alternative of allowing owners/operators to quantify the emissions reductions from other on-site sources attributable to the well closure including the following:

- Emissions from natural gas driven process controllers on the wellheads (e.g. emergency shutdown, plunger-lift controls) should be eligible for the exemption.
- Emissions associated with the storage vessels that may now have reduced throughput as a consequence of the well closure.
- Emissions from permanently plugged natural gas storage wells and related equipment.

Additionally, EPA was incorrect to exclude emissions from facilities that are below the waste emissions threshold from the exemption.[57] This limitation is not supported by the clear statutory requirement that "charges shall not be imposed" for emissions associated with plugged wells because it precludes the netting of emissions attributable to plugged wells that fall below the applicable waste emissions threshold.

5.2 EPA must avoid imposing reporting and recordkeeping requirements that are duplicative with other existing well closure requirements.

EPA must avoid reporting and recordkeeping requirements that are duplicative with other well closure requirements. Well closure requirements are within the jurisdiction of State Oil & Gas Commissions and other agencies, not the EPA. Under state law, a well is required to be plugged and abandoned when it has reached the end of its useful life. In all States, operators must provide written notice of plugging and comply with regulatory requirements to plug and abandon the well, including removing equipment, setting downhole plugs, cementing in the casing, capping the well to prevent fluid migration and restoring the surface site. These practices are done to permanently confine oil, gas and water into the strata in which they were originally found. For wells located on federal lands, separate BLM requirements also apply for well closure. Depending on the well location (e.g., located in an area with potash mining), additional requirements may also apply. EPA has also finalized closure plan requirements under OOOObc, see Attachment A for API's detailed comments on these requirements. EPA

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[56] *Id.* at 5348.

[57] 89 FR 5347

must avoid adding a potentially fifth set of recordkeeping and reporting requirements related to well closure with the exemption for permanently shut-in and plugged wells under WEC.

States have jurisdiction on closure requirements and inclusion of attestation that the closure has been conducted per appropriate requirements would be appropriate for the purposes of implementing the WEC. However, EPA is proposing in § 99.51 (a)(3) that operators submit "the statutory citation for each applicable state, local, and federal regulation stipulating requirements that were applicable to the closure of the permanently shut-in and plugged well." This level of information is unnecessary to verify the exemption and adds no environmental benefit under the WEC because it creates an opportunity for operators to inadvertently miss a citation. A missed citation for this reporting effort would not necessarily mean that the requirements were not followed during the permanent well closure. EPA should remove this list of citations from the reporting requirements.

6.0 Deadlines and Related Provisions

6.1 EPA's delay in setting up the supporting regulatory infrastructure should cause the WEC program to be deferred until 2025 or beyond.

The plain text of CAA § 136(g) specifies that the WEC "shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter." Additionally, CAA § 136(h) also required EPA to revise the requirements of Subpart W to more accurately reflect the total methane emissions and waste emissions for which an operator must demonstrate how much of a fee is owed. While EPA has proposed amendments to Subpart W, the final rule will not be promulgated until later in 2024. Likewise, EPA will not be able to promulgate the final WEC rule until later 2024. Moreover, under § 136(f)(6) the statute explicitly provides an exemption for operations that are in compliance with OOOObc, which has only recently been finalized.

Given EPA's delay in setting up the regulatory infrastructure that is necessitated in support of the statute, initiation of the WEC program should be deferred until the calendar year when all connected requirements and compliance obligations under both Subpart W and OOOObc are fully in effect.

6.2 EPA must redefine what constitutes a substantive error during validation of submitted Subpart W reports, which are the basis for the WEC.

As EPA explains in the preamble, while there is an annual March 31 deadline for submitting Subpart W reports, that "deadline" marks the beginning of a validation process that allows for Subpart W reports to be updated well after initial submission (in some cases, years after).[58] This validation process occurs within the e-GGRT platform whereby EPA sends operators questions.[59] Operators can respond via a text-based response and/or resubmit their emissions report. Many times, these queries can be closed without further action or only necessitate an administrative update where no change in reported emissions occurs to fully close the query. When an operator response does result in a change of total reported emissions these changes are often de minimis or immaterial to the overall reported emissions.

EPA must consider the impact of its inquiries during the validation process given that Subpart W is now the basis for calculating the WEC fee. At minimum, EPA should limit inquiries after WEC payments are received to those

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[58] 89 FR 5350

[59] We note that this validation process is not typical under any other EPA emission reporting program.

that could result in a true substantive change[60] of reported emissions under Part 98. API and other trades suggested 5% of a facility's total emissions as substantive in comments submitted on EPA's proposed Subpart W, which we have included as Attachment B. This would reduce the administrative burden for both EPA and operators by focusing queries on topics that are most important to emissions quantified. Consistent with our comments pursuant to proposed Subpart W included in Attachment B, this still provides time for EPA to validate emissions, but cease the seemingly unending questioning that continue to arise on Subpart W reports years after they have been originally submitted under Part 98.[61]

6.3 The WEC Filing, including payment, should occur only when both Subpart W and WEC filings have been validated to avoid a prolonged cycle of additional payments or refunds.

As proposed, EPA has created an untenable timeline for processing data, making payments, validating data, and refunding partial payments. Instead, EPA should make the reporting/validation/correction processes under the two programs wholly consistent, meaning that WEC filings should be based on validated Subpart W data and the WEC payment should be due after the WEC filing has been confirmed by EPA.

In order for a designated representative to certify the WEC filing, additional checks on ALL calculations, including all Subpart W calculations, would be necessary prior to submitting the WEC. Setting the WEC filing deadline to be the same as the Subpart W reporting deadline effectively pushes up when operators would need to complete the Subpart W calculations because the WEC filing can only be completed after all Subpart W reports are completed by an operator and additional lead time is needed to process the payment to go with the WEC filing.

Therefore, we offer the following amended timeline to support a more tenable workflow pursuant to the WEC:

- **Operators submit emissions reports pursuant to Subpart W by March 31 for the prior calendar year emissions, as required under 40 CFR Part 98.**
- **The proposed WEC filing deadline should be delayed until November 1 under proposed Part 99**. The emissions reported under Subpart W are the starting point for the WEC, but the WEC includes additional calculations and assessments that will require additional time to complete.
    - The delay to November 1 for the WEC Filing provides EPA time to conduct preliminary verification on reported values, which increases certainty on the regulated community. This timeline also coincides with the usual schedule of when EPA publicly publishes Subpart W data within the FLIGHT database and in other publications after conducting their initial validation/verification process.
    - The additional time also allows operators to assess and review their WEC filing and estimate their fee. A later deadline will allow operators to:

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[60] Per the GHG Protocol: *"A threshold is often used by verifiers to determine whether an error or omission is a material discrepancy or not. A material discrepancy is an error (for example, from an oversight, omission or miscalculation) that results in a reported quantity or statement being significantly different to the true value or meaning. As a rule of thumb, an error is considered to be materially misleading if its value exceeds 5% of the total inventory for the part of the organization being verified."* This is a relevant marker in determining if any omission influences the outcome in a meaningful way. We note here that materiality as discussed in the context of GHG emission reporting is highly variable and different from how the concept of "materiality" is defined per the Securities and Exchange Commission. Here we refer to materiality as defined and referenced strictly in the GHG Protocol Corporate Standard as a reference for how EPA should redefine what classifies a truly substantive error under the GHGRP.

[61] We note that this concept varies from how EPA reviews the concept of a 'substantive' change, which are essentially includes any change that might be required to the report – even if minor or administrative in nature.

    - Carefully consider potential exemptions and perform the necessary netting and additional calculations that are part of the WEC filing. Completing these additional calculations at the same time as completing the annual Subpart W emission report is untenable as proposed.
    - Review and resubmit information reported under Subpart W that may be identified on the part of the operator during preparation of the WEC filing. This will alleviate the administrative burden of both operators and EPA in the overall validation process ahead of the WEC filing.
    - Review their OOOObc compliance records, which are due on a differing reporting cycle than Subpart W. This could also alleviate the burden associated with resubmitting the WEC filing as even EPA acknowledges that OOOObc compliance reports will not be complete by March 31 each year[62].

- **The deadline for submitting the WEC Payment that is part of the proposed WEC Filing should also be delayed until November 1 under Part 99.**
  - We agree that any fee should be due in the same year the emissions are reported to not prolong uncertainty in capital planning associated with the fee. Also, the administrative burden of additional fee collection and refunds due to fee corrections would be reduced by delaying payment until November 1. We also agree with EPA assertions that any Subpart W report that is resubmitted after November 1 that impacts the WEC calculations would not necessitate a revised WEC filing; operators could continue to resubmit data under Subpart W at any time.
  - Companies often have lead times to have funds approved or checks issued. It is impractical for operators to complete their emission reports and be prepared to issue a check associated with the emissions quantified at the same time, especially given the additional calculations associated with the WEC framework (including exemptions).
  - WEC payments resulting from any revision during the validation process of WEC filings should not be subject to interest or penalties.

6.4 EPA should establish a consistent requirement that relevant records under Subpart W and the WEC program must be retained only for three years following a given reporting year.

EPA should establish a consistent requirement that relevant records under Subpart W and the WEC program must be retained only for three years following a given reporting year. To provide needed repose for owners/operators, that three- year deadline also should mark the end of EPA's and the owner/operator's opportunity or obligation to file amended reports and to amend any required WEC payments.

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[62] 89 FR 5346

7.0 Facility Definition

7.1 EPA's proposed approach is procedurally inadequate because EPA does not provide any meaningful legal, policy, or factual analysis of the statutory term "applicable facility" as it relates to defining the geographic bounds of such facilities and no explanation as to how the approach for reporting facility level emissions under Subpart W satisfies the meaning of "applicable facility" under CAA § 136.

EPA proposes that an "applicable facility" means "a facility within one or more … industry segments, as those industry segment terms are defined in §98.230 of this chapter."[63] EPA explains in the preamble that that definition includes a "facility for which the owner or operator of the Subpart W reporting facility reported GHG emissions under Subpart W of more than 25,000 mt CO2e."[64] EPA further explains that "[i]n cases where a Subpart W facility reports under two or more of the industry segments listed in the previous paragraph, the EPA proposes that the 25,000 mt CO2e threshold would be evaluated based on the total facility GHG emissions reported to Subpart W across all of the industry segments (i.e., the facility's total Subpart W GHGs)."[65] EPA provides no further regulatory text or preamble discussion to elaborate on the boundaries of an "applicable facility."

Although it is far from clear in the Proposed Rule, it appears that EPA intends the WEC rule to be implemented according to how facility level emissions must be reported under Subpart W. In other words, EPA effectively relies on Subpart W reporting requirements for defining the geographic bounds of an "applicable facility" under the WEC rule. That aspect of the proposed rule is flawed because EPA fails to provide adequate explanation or justification for taking that approach.

The crux of the problem is that CAA § 136 states that an "applicable facility" is a "facility" within specified industry segments "as defined in Subpart W."[66] The reference to Subpart W plainly is a reference to the industry segments already defined in Subpart W and not a reference to how emissions sources must be grouped for purposes of estimating and reporting emissions under Subpart W. Thus, the CAA § 136 definition of "applicable facility" leaves open the question of what are the geographic bounds of a "facility" under the WEC program?[67]

In other circumstances, the term "facility" refers to a plant-like collection of equipment or operations that is under common ownership or control and that is contained within a geographically contiguous or adjacent area. Such plant-like facilities are not uncommon in the oil and gas production sector. For example, a natural gas processing plant often comprises a discrete plant-like facility.

But the generally dispersed nature of functionally interrelated upstream oil and gas production has made it difficult in some circumstances to determine the physical bounds of a facility for CAA regulatory purposes. EPA has observed that "well sites can be located hundreds of miles from the natural gas processing plant, and some oil and gas operations (e.g., a production field) can cover many square miles."[68] Adding to that complexity is the fact that "unlike many industries, land ownership and control are not easily distinguished in this industry, because

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[63] 89 FR 5367.

[64] 89 FR 5324.

[65] *Id.*

[66] CAA § 136(d).

[67] Notably, EPA did not address the definition of "facility" or "applicable facility" in the recent proposed changes to Subpart W of the GHGRP. EPA explained that "implementation of the waste emissions charge is outside the scope of this rulemaking." 88 Fed. Reg. 50282, 50286 (Aug. 1, 2023).

[68] Memo from William L. Wehrum to Regional Administrators I-X, Source Determinations for Oil and Gas Industries (Jan. 12, 2007) at 2.

subsurface and surface property rights are often owned and leased by different entities, and drilling and exploration activities are contracted to third parties."[69] Moreover, [w]hile it is not uncommon for a single company to gain the use of a large area of contiguous property through these lease and mineral rights agreements, owners or operators of production field facilities typically control only the surface area necessary to operate the physical structures used in oil and gas production, and not the land between well drill sites."[70]

Those unique industry characteristics have been handled in various ways under relevant CAA programs. For example, Congress itself specified under the CAA § 112 air toxics program that "emissions from any oil or gas exploration or production well (with associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section."[71] Congress thus recognized the potential confusion that might arise as to how oil and gas production operations should be grouped for purposes of identifying and administering the CAA § 112 air toxics program and gave EPA detailed instructions for addressing such operations in a discrete, plant-like fashion.

Similarly, in the absence of such industry-specific direction from Congress under the CAA Title I preconstruction permitting programs and Title V operating permit program, EPA promulgated regulations directing that source determinations under those programs should focus on geographically discrete collections of equipment and operations. Under the Title V program ,a major source is defined as "any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties …)" and specifying that "[f]or onshore activities belonging to Standard Industrial Classification (SIC) Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1⁄4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment.".[72]

EPA took a different approach in Subpart W of the GHGRP. There, EPA observed that "[f]or some segments of the industry (e.g., onshore natural gas processing, onshore natural gas transmission compression, and offshore petroleum and natural gas production), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying the scope of reporting and responsible reporting entities."[73] But, consistent with EPA's experience under the air toxics and permitting programs, EPA observed that "in onshore petroleum and natural gas production and natural gas distribution such distinctions are more challenging."[74]

EPA concluded that "it was necessary to provide a unique definition of facility for each of these two segments in order to ensure that the reporting delineation is clear, avoid double counting, and ensure appropriate emissions coverage."[75] That "unique definition of facility" called for aggregation of all operations under common ownership or control within a given hydrocarbon basin.[76] While that broader Subpart W definition of "facility" served the unique, non-substantive information-gathering purposes of Subpart W, EPA cautioned that "[t]hese definitions

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[69] *Id*.
[70] *Id* at 2-3.
[71] CAA § 112(n)(4)(A)
[72] 40 C.F.R. Part 71.2
[73] 75 Fed. Reg. 74458, 74466-7 (Nov. 30, 2010).
[74] *Id*. at 74467.
[75] *Id*.
[76] *Id*.

are intended only for purposes of Subpart W and are not intended to affect the definition of a facility as it might be applied in any other context of the Clean Air Act."[77]

Notably, EPA issued the GHGRP primarily under the general information gathering authority of CAA § 114, which in relevant part authorizes EPA to obtain information from "any person who owns or operates ***any emissions source***," but does not otherwise explain what constitutes a "source" under that section. CAA § 114(a)(1) (emphasis added). Given the lack of any other CAA provision authorizing or governing the GHGRP, EPA's "facility" definition for the oil and gas sector in Subpart W is not necessarily applicable in deciding how "facility" (or functionally similar terms) should be defined under substantive CAA programs – including the WEC rule.

In sum, defining "facility" (or functionally similar terms) under the CAA is "challenging" in the oil and gas production sector given the unique nature of the operations and the wide geographic dispersal of interrelated operations. Under the substantive CAA programs (i.e., those that impose emissions limitations or standards), EPA is required or, for good and compelling reasons, has opted to adopt an approach that focuses on geographically discrete operations rather than aggregating interrelated operations dispersed over a wide geographic area. Conversely, under the purely informational GHGRP (a program that is not governed by any express CAA provision), EPA decided for program-specific purposes to aggregate operations at a basin level, with a caution that such an approach was "not intended to affect" how a facility is defined under other CAA programs.

That backdrop shows that there is an acute need to define the term "facility" when regulating the oil and gas sector under the CAA. That need is particularly pronounced here given that the geographic bounds of an "applicable facility" are not prescribed in CAA § 136 and there is no indication that the definition of "facility" used in Subpart W of the GHGRP must be applied. Moreover, it is not necessarily reasonable to assume or infer that the basin-wide definition of facility that EPA coined under Subpart W solely for purposes of facilitating the collection of GHG emissions information is appropriate under the WEC rule, which serves the very different purpose of imposing methane emissions fees in prescribed circumstances.

Yet, as noted above, EPA in the Proposed Rule does not describe the geographic boundaries of an applicable facility or otherwise acknowledge or discuss that important topic. EPA seems to assume that the Subpart W facility definition will apply under the WEC rule. But that tacit assumption does not provide the explanation needed to fully understand the Agency's factual, policy, and legal rationale on such a key element of the Proposed Rule.[78] As a result, commenters do not have adequate notice to develop informed comments. Also, for the same reasons, EPA has not satisfied its obligation under CAA § 307(d)(3)(C) to explain the "major legal interpretations and policy considerations underlying the proposed rule." Prior to finalizing the rule, EPA must provide further clarity as to the proposed bounds of an "applicable facility" and provide an opportunity for public comments on that proposal.

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[77] *Id.*

[78] For example, EPA explains in passing that "for certain industry segments a single reporting facility may represent operations in two or more industry segments." *Id.* at 5323. EPA proposes that, "[t]o accommodate for such facilities, we are proposing within the definition of "applicable facility" that such operations would be considered a single applicable facility under part 99." *Id.* But the proposal to combine emissions from multiple industry segments located within a single physical "facility" is at odds with the segment-specific definitions for the various facilities that must report under Part 98. See, e.g., § 98.238 (definition of "facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for corresponding subpart A requirements"). To allow for informed comments, EPA must explain why "applicable facility" under CAA § 136 should be different than a "facility" under Subpart W. Moreover, EPA asserts at several places in the Proposed Rule that, because Part 98 preexisted CAA § 136 and the WEC regulatory program, it should be presumed that Congress intended relevant provisions of Part 98 to be applied in the WEC program. See, e.g., 89 Fed. Reg. at 5328 (Part 98 was "an established program at the time that Congress drafted CAA section 136."). But when EPA must make changes to existing Part 98 provisions – such as the segment specific facility definitions – the fact that Part 98 preceded CAA § 136 has little bearing on implementation of CAA § 136.

7.2 EPA must consider all relevant factors when making regulatory decisions and did not provide analysis of how regulatory alternatives would affect the scope of applicability of the WEC.

A broader problem with the Proposed Rule related to these issues is the Agency's failure to consider three of the most important factors related to implementation of CAA § 136 – how the many decisions EPA must make in devising the regulatory program affect: (1) applicability of the WEC program (e.g., how many facilities will exceed the 25,000 tpy emissions threshold); (2) the number of facilities that trigger the obligation to pay a fee; and (3) for those owing a fee, the amount of that fee. Instead, EPA appears to have made an unstated assumption that it should maximize applicability of the WEC program and maximize the fees paid under the program rather than design the program to further incentivize emissions reductions. For example, as discussed, EPA proposes that netting should be allowed only at the subsidiary level and not among operators owned by a larger parent company and proposes that facilities with less than 25,000 tpy of emissions are not eligible to participate in netting. Those proposed provisions plainly would require owner/operators to pay more fees than Congress intended by excluding facilities from netting where emissions have been brought below WEC thresholds.

Also as discussed, EPA proposes numerous constraints on implementation of the regulatory compliance exemption, such that it would not become available until several years after the WEC rule becomes effective and would be virtually impossible for any applicable facility to achieve.

For each of these examples (and more broadly for other key program elements presented throughout the Proposed Rule as a whole) EPA provides no analysis of how the regulatory alternatives would affect the scope of applicability of the WEC rule, the number of entities required to pay, and the fees that would be due. EPA also fails to assess how the differing impacts on those critical program factors would affect overall program implementation. For example, EPA does not consider whether incentives to reduce emissions would be greater or lesser, whether differences in fee payments would be material, and whether the regulatory alternatives promote or detract from the overall program purposes and Congressional intent.

EPA, of course, is obligated to consider all relevant factors when making regulatory decisions.[79] ("Normally, an agency rule would be arbitrary and capricious if the agency … entirely failed to consider an important aspect of the problem."). EPA falls short of that obligation here by failing to assess the programmatic consequences of the key regulatory alternatives.

Lastly, we note that the Proposed Rule incorporates elements of Subpart W that EPA has proposed to adopt, but as of the date of these comments has not issued in a final rule.[80] Because the Subpart W amendments that EPA proposed for purposes of implementing the WEC program are not yet final, we have no opportunity to understand whether the not-yet-final Subpart W provisions will function appropriately under the WEC program. We thus are unable to provide informed comments on these important issues in the context of this Proposed Rule.

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[79] *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29 (1983) at 43

[80] See, e.g., 89 Fed. Reg. at 5374 (proposed § 99.20(c), requiring for "RY 2025 and later" the use of proposed § 98.236(aa)(3)(ix)).

8.0 Other General Comments

8.1 Facilities that do not sell natural gas should be exempt from the WEC.

EPA notes in the preamble to the proposed WEC rule that a number of gathering and boosting facilities exist that do not send gas to sale and, as a result, would report zero natural gas volumes used in the waste emissions threshold calculations and, therefore, all reported methane emissions would be considered to be exceeding the waste emissions threshold and subject to the fee. EPA asserts this, "is based on a plain reading of the statutory text." We disagree.

The statutory text at section 136(f)(2) reads:

> With respect to imposing and collecting the charge under subsection (c) for an applicable facility in an industry segment listed in paragraph (3), (6), (7), or (8) of subsection (d), the Administrator shall impose and collect the charge on the reported metric tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facility. [emphasis added]

A plain reading of this text conveys that gathering and boosting facilities that do not send gas to sale are simply not contemplated by the statute. EPA has invited comment on the prospect that all methane emissions from such facilities should be considered below the waste emissions threshold. We believe this is the appropriate and statutorily supportable approach.

It is inappropriate to charge such facilities fees in the absence of a threshold when such thresholds exist for other industry segments. Simply applying a waste emissions threshold of zero is both punitive to well designed and efficient gathering and boosting facilities not engaged in gas sales and in plain contradiction of the enabling statutory language.

8.2 Facilities under construction should be clearly defined as exempt under the WEC.

Facilities that are not yet producing any oil or gas for sale, but are in the process of being constructed, are not wasting methane or losing it as a result of routine operations, and therefore should not be assessed any fees during the construction period. Emissions that occur during this period are primarily combustion emissions associated with the drilling rig or other fuel combustion sources necessary for the construction. There will be minor amounts of methane generated during well testing prior to bringing the well online but those emissions are temporary, minor, and unavoidable.

EPA explains in the preamble that "the WEC provides an incentive for the early adoption of methane emission reduction practices and technologies" and that "Congress structured the WEC so that it focuses on high-emitting oil and gas facilities". EPA further highlights in the preamble that "Facility efficiency in terms of methane emissions per unit of production or throughput would have a large impact on the amount of the WEC owed, with more efficient facilities expected to have emissions falling below the specified thresholds". New facilities, which are focused on early adoption of methane emissions reduction practices during the design stage, do not benefit from the incentives intended by WEC. These new more efficient facilities are expected to have emissions falling below the specified thresholds after start-up and once production begins. However, during construction/pre-production years, they are unable to utilize the waste emissions threshold calculation to demonstrate that.

For these reasons, an exemption should be provided for facilities in pre-production phase that are designed with early adoption of methane emission reduction practices and technologies.

Alternatively, later reporting applicability could be considered for facilities in pre-production phase that are designed with early adoption of methane emission reduction practices and technologies, similar to treatment of delineation wells under Subpart W:

> "You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the well ID number(s) for the well(s) included in the number."

In this manner, the waste emissions threshold could be applied to the methane emissions that occur during the period of construction so that benefit is not lost and the well-designed facility is not penalized.

8.3 Comments on Confidentiality Determinations

EPA proposes that the name and contact information for the designated representative of the WEC obligated party are "emissions data" and therefore not confidential. We do not believe the personal contact information about personnel including the name, address and email should not be considered emissions data and available publicly.

8.4 Cross Reference and other Minor Clarifications

Below are some cross reference and other typographical errors we have identified within the proposed WEC regulatory text.

- 99.2 – proposed definitions of "gathering and boosting system" and "gathering and boosting system owner or operator" do not match the proposed revisions under Subpart W. Definitions should be aligned between Part 98 and Part 99.
- 99.31(a) – "§ 99.30(a) through (f)" should be "§ 99.30(a) through (e)".
- 99.31(b) – "paragraphs (b)(1) through (10) of this section" should be "paragraphs (b)(1) through (11) of this section".
- 99.31(b)(8) – "Nnatural gas" should be "natural gas".
- 99.32(b)(1) – References to Subpart W may need to be updated based on proposed Subpart W revisions.
- 99.41(c) – the word "requirement" is repeated, and the second instance should be deleted.
- Cross references to the regulatory compliance exemption may need to be clarified.
    - 99.7(b)(2)(iv) – "99.41" should be "99.42"; "99.40" might need to be "99.41".
    - 99.8(c)(2)(i) – "99.41" should be "99.42".
    - 99.8(d)(2) – "99.41(c)" should be "99.42(c)".
    - 99.21(c) – "99.40" might need to be "99.41".

  - 99.21(d) – "99.40" might need to be "99.41".
  - 99.22 – "99.40" might need to be "99.41".
  - 99.40(c) – "99.41" should be "99.42".
  - 99.40(d) – "99.41" should be "99.42".
  - 99.41(a) – language appears inconsistent with 99.40(a). Reference to "99.21(d)" should be removed since that citation says that the regulatory exemption does not apply.

Attachment A

Previous API Comments on “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources” Oil and Natural Gas Sector Climate Review

(NSPS OOOOb and EG OOOOc)

Docket No. EPA-HQ-OAR-2021-0317

Letters Submitted

February 13, 2023 & January 31, 2022

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February 13, 2023

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W. Washington, D.C. 20460

Attention: Docket ID EPA-HQ-OAR-2021-0317

RE: Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Including Appendix K and Social Cost of Greenhouse Gases

Dear Administrator Regan:

The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (87 FR 74702, December 6, 2022) ("Supplemental Proposal"). This submittal includes comments on the associated Appendix K proposal and EPA's "Report on the Social Cost of Greenhouse Gases".

API is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. Gross Domestic Product (GDP). API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators, and marine transporters, as well as service and supply companies, providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

As we indicated in our comments on EPA's November 2021 Proposal (86 FR 63110, November 15, 2021), API supports the cost-effective, technically feasible, direct federal regulation of methane from new and existing sources across the supply chain. We appreciate EPA's further development of a fugitive emissions monitoring framework that allows for use of advanced detection technologies. We also appreciate EPA's recognition that Appendix K's monitoring protocol is not appropriate for the upstream production and transmission segments. While we appreciate EPA's responsiveness to many of the issues raised in our comments[1] on the November 2021 Proposal, nevertheless, we have serious concerns regarding the cost effectiveness, technical feasibility, and legal soundness of many aspects of the Supplemental Proposal. We also have extensive concerns with EPA's Draft Report on the Social Cost of Greenhouse Gases and the lack of transparency in the Interagency Working Group's process. Moreover, we strongly disagree with EPA's assertion[2] that November 15, 2021 can serve as the applicability date of the final rule for new, reconstructed, and modified sources.

Reducing methane emissions is a shared priority for EPA and our industry. We are committed to advancing the development, testing, and utilization of new technologies and practices to better understand, detect, and further mitigate emissions. In recent years, energy producers have implemented leak detection and repair (LDAR) programs, phased out the use of high-bleed pneumatic controllers, and reduced emissions associated with flaring – voluntarily and under federal and state regulations. Voluntary, industry-led initiatives such as The Environmental Partnership[3] have built on the progress industry has made to reduce emissions and continuously improve environmental performance. Since its founding in 2017, the Partnership has grown to include over 100 companies representing over 70% of total U.S. onshore oil and natural gas production.

The New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc are complex rules that will apply to hundreds of thousands of facilities owned and operated by these and other companies, including many facilities that have not previously been subject to regulation under the Clean Air Act. Because of the wide variety of conditions faced by these facilities, the novel nature of a first ever existing source rule, and timing of the Supplemental Proposal's release and subsequent overlap with the holiday season, API requested[4] an extension of the comment period to allow additional time for our staff and our members to fully review the Supplemental Proposal and provide EPA with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. As we noted, API members who are engaged on this issue have been concurrently engaged in reviewing additional recent legal and regulatory developments on this subject matter. We regret that EPA did not grant the request and may rush to completion of a final rule that does not reflect the full measure of consideration necessary to ensure cost effectiveness, technical feasibility, and legal soundness.

In our review of the Supplemental Proposal, API once again considered the effectiveness of emission reduction strategies, safety, feasibility, operability, and cost. Where appropriate, we have recommended changes to the regulatory text that will enable the final rule to meet these critically

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[1] EPA-HQ-OAR-2021-0317-0808
[2] 87 FR 74716
[3] http://www.theenvironmentalpartnership.com
[4] EPA-HQ-OAR-2021-0317-1588

important criteria. We have also detailed the necessity of workable implementation timelines that consider the supply chain and labor constraints facing our industry, constraints which will be exacerbated as the final rule takes effect. The adoption of the recommendations in our comments in the final rule would reflect a more cost-effective and technically feasible regulation of methane.

API appreciates EPA's engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize a cost-effective rule that incentivizes innovation, advances the progress made in reducing emissions and addressing climate change, and ensures that our industry can continue to provide the world with the affordable, reliable energy it requires.

If you have any questions regarding the content of these comments, please contact Ryan Steadley at steadleyr@api.org.

Sincerely,

cc:

Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Karen Marsh, EPA
Steve Fruh, EPA
Amy Hambrick, EPA

API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"

(Proposed NSPS OOOOb, EG OOOOc, Appendix K and the Social Cost of Greenhouse Gases)

Docket ID: EPA-HQ-OAR-2021-0317

February 13, 2023

Executive Summary

The American Petroleum Institute (API) supports certain aspects of the Supplemental Proposal for New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc and remains committed to working with the Environmental Protection Agency (EPA) and the Administration to identify cost-effective emission control opportunities. The comments provided herein focus on legal, technical, and feasibility challenges with specific provisions that EPA included within the Supplemental Proposal of NSPS OOOOb and EG OOOOc. Listed below are API's primary concerns with the proposed rules.

To facilitate review of our comments, API has summarized these concerns and provided reference to the detailed comments where additional supporting discussion has been included. Our members look forward to continued dialogue and engagement as EPA works towards finalizing these important rules.

1) **The Applicability Date for NSPS OOOOb should be December 6, 2022.**
   The Clean Air Act (CAA) Section (§) 111(a)(2) definition of "new source" uses the term "proposed regulations" in defining the new source trigger date. The November 2021 preamble alone cannot constitute a proposed rule any more than a final rule that is unaccompanied by regulatory text could be declared a "rule." Although the November 2021 preamble described the type of regulatory requirements that EPA contemplated promulgating, the preamble was not in and of itself a document that establishes the "agency statement of general or particular applicability and future effect." That type of required statement would be established only by the proposed regulatory text, which was not provided until the December 2022 Supplemental Proposal. Many of the requirements included in the proposed regulatory text could not have been gleaned from the prior descriptions provided. Refer to Comment 8.1 and Comment 12.1.

2) **Adequate implementation time must be provided for NSPS OOOOb and EG OOOOc.**
   NSPS OOOOb and EG OOOOc will apply to hundreds of thousands of sites when implemented. Our members are already experiencing a noticeable delay in the supply chain for equipment required by the proposed rules including (but not limited to) control devices, flow monitoring equipment, instrument air systems, solar panels, etc. Control devices are currently experiencing delays of 3 to4 months, while flow monitors are on backorder for a minimum of 6 to8 months from suppliers. Instrument air systems (including the air compressor and associated equipment) are nearly 1 year on backorder, and recently ordered solar panels are delayed between 18 to24 months. As more facilities become subject to proposed requirements in NSPS OOOOb and EG OOOOc, the above timelines are anticipated to be exacerbated before the market experiences a correction to meet these new levels of demand. We provide more detail related to current supply chain delays in Comment 5.2 and Comment 7.1. We request EPA consider these challenges prior to finalization of certain provisions within these rules to allow operators the ability to acquire and install the required equipment. Additionally, EPA should allow more time for new, modified, and reconstructed sources to come into compliance with NSPS OOOOb if it maintains the current applicability date of November 15, 2021.

3) **Associated gas provisions need to be significantly modified.**
Whereas API supports and recognizes the environmental benefit of eliminating the venting of associated gas from oil wells, EPA must recognize the distinction between associated gas from oil wells that route to a sales line and oil wells that do not have adequate or accessible gas gathering infrastructure. Removing wells connected to sales lines (or recovering gas for another primary purpose) from the requirements of the associated gas provisions would help to eliminate confusion resulting from EPA introducing its own interpretation of "flaring" when multiple definitions of "routine flaring" already exist in state and voluntary programs. Additionally, API does not support the requirement to make an infeasibility demonstration, along with safety and technical certifications in order to flare associated gas. Refer to Comment 4.0. and Comment 12.9.

4) **As proposed, the Super-Emitter Response Program presents numerous legal, logistical, commercial, safety, and security risks that have not been adequately considered by EPA within the Supplemental Proposal.**
To address these concerns (and assuming EPA resolves the legal deficiencies), numerous adjustments to the proposed framework are necessary. Specifically, EPA must establish requirements for monitoring of third-party data, provide a formal notification process that includes EPA involvement and review, and provide limitations on how any monitored data is released and used publicly. Refer to Comment 1.0, Comment 12.3, and Comment 12.4.

5) **In determining storage vessels affected facility Potential to Emit, EPA's proposed criteria for legally and practicably enforceable limits have broad legal implications and pose several permitting challenges.**
The proposed criteria and the additional methane emissions threshold may be lacking in existing permits that have previously been understood to be legally and practicably enforceable and may also be impossible to obtain under existing permitting mechanisms. EPA should continue to defer to the states on sufficient monitoring, recordkeeping, and reporting requirements to include in permits to establish legally and practicably enforceable limits. API also offers suggestions concerning various definitions and proposed control requirements for storage vessels affected facilities. Refer to Comment 6.0. and Comment 12.10.

6) **As proposed, alternative technology requirements for fugitive emissions monitoring, including continuous monitoring, are impractical and may disincentivize the use of this emerging technology.**
API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA to make key adjustments in the final rule to enhance the use, and not unintentionally disincentivize development and deployment of these technologies. In particular, we believe there should be approved technologies for operators' use at the time the rule is finalized, alternate technologies should not be held to a greater level of stringency (i.e., frequency) than Best System of Emission Reduction (BSER) as currently proposed, and EPA should streamline the timeline and actions to conduct repairs. Refer to Comment 3.0.

7) **API proposes AVO inspections only at multi-wellhead only sites.**
EPA's focus on finding large fugitive emissions at single wellhead only sites using audio, visual, olfactory (AVO) inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall

well site emissions. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Refer to Comment 2.1.

8) **EPA should clarify its preamble language concerning leaks detected from a cover or a closed vent system during associated inspections or other fugitive emissions monitoring.**
Emissions detected from covers and closed vent systems do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented. Like standards for other fugitive emissions components, the "no identifiable emissions" standard is a work practice standard rather than a numerical emissions standard. Therefore, EPA must make it clear that a cover or closed vent system remains in compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed. Regarding control devices, API recommends a compliance extension of at least one year for the proposed monitoring requirements. We also offer suggestions to provide consistency between manufacturer-tested devices and other enclosed combustion devices as well as request EPA provide the necessary monitoring alternatives given the increased number of control devices subject to proposed monitoring requirements. Refer to Comment 5.0.

9) **EPA should amend many of the provisions within the Supplemental Proposal to work practice standards and eliminate the additional technical demonstrations with accompanying certification statements.**
EPA has added several certification statements throughout the proposed requirements for NSPS OOOOb and EG OOOOc – including certifications for pneumatic pumps, gas well liquids unloading operations, and associated gas from oil wells. EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating exceptions that require technical demonstrations and engineering certification. Inclusion of these technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA § 111 because non-emitting standards are not "adequately demonstrated" if exceptions are needed to make them feasible and workable. Regarding the certification statements themselves, a certified official is already required to sign the report certifying the company's compliance with all applicable provisions. These additional certifications should be removed prior to finalization of these standards for associated gas from oil wells, pneumatic pumps, and gas well liquids unloading operations. Refer to Comment 4.1, Comment 8.2, Comment 9.1, Comment 10.1, and Comment 12.9

10) **Requirements for pneumatic controllers and pneumatics pumps should be simplified and aligned.**
While we support EPA's proposal for defining the affected facility for both pneumatic controllers and pumps as the collective, we have numerous concerns with the practical and logistical aspects of how EPA has outlined control standards between the two sources. Specifically, EPA has proposed a completely distinct set of requirements for natural gas-driven controllers separate from natural gas-driven pneumatic pumps with sometimes conflicting statements made to justify EPA's decisions. The requirements for both pneumatic controllers and pumps should be streamlined for consistency with neutral technology standards that do not require additional certifications and allow for emissions to be routed to a control device. Refer to Comment 7.0 and Comment 8.0.

11) **EPA should streamline the recordkeeping and reporting requirements associated with compliance assurance of the proposed rules.**
EPA should continue to streamline both recordkeeping and reporting as it relates to these proposed requirements to include only the necessary information that will help assure compliance. Streamlining is especially critical for locations with existing sources as the cumulative impacts for tracking records are anticipated to be much larger than EPA estimates and will apply to hundreds of thousands of sites across the U.S. For some sources, EPA has described requiring records and potential reporting of information that does not link directly to emission controls or work practices, which API does not support. We support inclusion of recordkeeping and reporting that help demonstrate compliance with less administrative burden. Refer to Comment 9.3 and Comment 13.2.

12) **EPA should grant equivalency for state programs across emission sources for NSPS OOOOb and EG OOOOc.**
Given EPA has described many requirements that are consistent with those at the state level (e.g., Colorado, New Mexico, and California), EPA should allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb and EG OOOOc where it is appropriate to do so for leak detection and repair (fugitive emission monitoring) and other emission control provisions. EPA should allow states the opportunity to demonstrate programmatic equivalency, including addressing deviations from the form of the proposed standards. Without this, states and operators may be administering and complying with two sets of requirements (standards and administrative) that are duplicative because they are intended to achieve similar goals but are not perfectly identical. It also precludes innovative regulatory approaches from states. Refer to Comment 12.6 and Comment 12.7.

13) **EPA should carefully consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc in conjunction with the cumulative burden imposed through provisons in the Supplemental Proposal.**
EPA must consider the cumulative burden imposed to the regulated community of numerous and onerous provisions in the Supplemental Proposal, especially due to the unprecedented number of sources that will be subject to the rule given the proposed November 2021 applicability date for new, modified, and reconstructed sources. EPA must also consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc and the difficulty the industry has faced to fully understand the impacts of this rule without a comment extension. These difficulties for the regulated community have been compounded by other rules that impact the same sources (e.g., Bureau of Land Management's (BLM's) Waste Prevention Proposal). Specifically, EPA needs to be clear on the disposition of NSPS OOOO and OOOOa applicable sources if and when they become subject to EG OOOOc. Finally, EPA must revise its Regulatory Impact Analysis, including the potential for lost production stemming from implementation of these rules. Refer to Comment 12.1 and Comment 12.5.

14) **For equipment leaks at onshore natural gas processing plants, API recommends that closed vent systems be monitored annually and that appropriate VOC and methane concentration thresholds be established for applicability.**
While API supports the proposed bimonthly OGI monitoring as well as the proposed alternative monitoring based on the incorporated NSPS VVa requirements with simplifications, we have concerns with the proposed frequency for closed vent systems and the proposed potential to emit applicability threshold for VOC. While we generally support the proposed Appendix K for OGI monitoring at gas plants, we have several comments regarding proposed Appendix K as provided in Attachment A. Other

comments on leak detection and repair at gas plants include our recommendation on the proposed definition of equipment for capital expenditure evaluations. Refer to Comment 11.0 and Attachment A.

15) **API appreciates EPA's decision to accept comments specifically on the EPA's Social Cost of Greenhouse Gas (SC-GHG) Report, but we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates.**
API shares the Administration's goal of reducing economy- wide GHG emissions. With respect to SC-GHG our concerns stem from the approach taken by EPA, including the anticipated role of these new estimates in EPA's rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group. Refer to Comment 13.5 and Attachment B.

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PROPOSED NSPS AND EMISSIONS GUIDELINES FOR THE OIL AND NATURAL GAS SECTOR (NSPS OOOOb AND EG OOOOc) INCLUDING APPENDIX K
DOCKET ID: EPA-HQ-OAR-2021-0317

While we have made every effort to thoroughly review both proposed New Source Performance Standard (NSPS) OOOOb and Emission Guidelines (EG) OOOOc as we formulated these comments, there may be places where we only provide a citation or reference as it pertains to proposed regulatory text in NSPS OOOOb. Unless we have provided a distinctly separate comment as the topic pertains to EG OOOOc, we also intend the comment to apply to proposed EG OOOOc. Additionally, when using the terms "proposal" or "standards" in these comments in reference to the November 2021 preamble, it does not constitute a "proposed rule" or "emission standard" for purposes of triggering applicability under CAA § 111(a)(2).

1.0 Super Emitter Response Program

As proposed, the Super Emitter Response Program (SERP) presents numerous legal[5], logistical, commercial, safety, and security risks that have not been adequately considered by the EPA and are the basis for the comments we offer herein. These complex issues would benefit from further discussions between EPA, operators, and other interested parties.

Our members understand the importance of identifying and addressing large emissions events and any future support for a program would be grounded in a shared interest to reduce the incidence of these emission events. For over three decades, EPA and industry have successfully collaborated on the implementation of voluntary programs to reduce methane emissions from the oil and natural gas sector under both the Natural Gas Star and Methane Challenge Programs. While we believe the SERP may be better suited to function as a voluntary based program, API members recognize the intent of the EPA to create a useable and workable program that identifies these large emissions events from a variety of stakeholders.

We encourage EPA to conduct additional outreach on the proposed framework and repropose a program that meets all Clean Air Act legal requirements prior to finalizing the requirements (as provided in §60.5371b). Our members would welcome the opportunity for future discussions on this important topic.

1.1 API proposes a programmatic framework that is managed by EPA and incentivizes the finding and subsequent repair of potential super emitter emission events.

EPA has described the SERP as a backstop to the requirements of NSPS OOOOb and EG OOOOc. However, as we describe throughout our comments there are serious legal, logistical, commercial, safety, and security problems inherent in EPA's proposed program. The framework we have described herein achieves the goals EPA has described for the program while addressing the concerns API members have with EPA's proposal.

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[5] See Comment 12.3 and 12.4 of this letter for a discussion of the numerous legal deficiencies underpinning the proposed SERP.

For the SERP to be effective, EPA must reconsider the operational flow of how the program will function and be implemented. This framework includes adding formal notifications first from third parties to EPA and then from EPA to operators. We also specifically offer suggestions on clear timelines for all participants of the program where information can be transferred in a clear and transparent order, which we have emphasized in our framework.

Below we have outlined our suggestions on the appropriate steps to be included in a reproposed framework, which provides greater confidence that the data provided under the program will be valid, actionable, and achieve EPA's goals for transparency within the program.

1) The third party completes approval certification process by EPA for inclusion in the Super-Emitter Response Program and becomes "certified or re-certified".
2) Certified third party[6] notifies EPA of planned monitoring, including submittal of a monitoring plan, at least **30 business days** prior to planned monitoring. Depending on technology deployed, such as satellites, this pre-approval may include flight plans for extended time periods. The components of the monitoring plan are more fully described in Comment 1.1.3 of this letter.
3) EPA reviews the certified third parties' monitoring plan for approval or disapproval.
    a. If approved, EPA notifies the impacted operators at least **7 business days prior** to monitoring with details of the monitoring to be conducted including technology planned for use, dates of monitoring, flight paths (if appropriate), etc. This notice essentially acts as a "pre-notification" to operators, which enables the operator to have staff available to ensure safety of operations, if warranted based on technology that will be used to detect potential emissions by a third-party.
    b. This "pre-notification" may also help both EPA and the third-party identify the appropriate operators, including the correct contact information, in the event a super emitting emissions event is detected. The potential for incorrect identification of operators is of concern for our members.
4) Timing of notification of results of monitoring to the operator is critical to the effectiveness of the SERP. After monitoring is completed, third party has **2 calendar days** to provide data as defined in §60.5371b(b) to the EPA.
5) If EPA determines the data provided by the third-party to be credible and warrants investigation, EPA provides data for any super emitter emission event to the appropriate operator(s) within **3 calendar days** of verification of third-party monitored data.[7]
6) Operator(s) will initiate an investigative analysis **within 5 business days** of receipt of data from EPA and complete the investigation within **10 business days** of receipt of the data from EPA.
    a. Given how certain technology is applied, the detection may not be from the facility that was notified, may be a permitted release, may be due to maintenance activity, or another reason that does not require action (such as monitoring data calibration issue). If the emissions event was the result of a permitted activity or could not be validated after full investigation by the operator, the

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[6] For the purpose of these comments when we reference a 'third-party', "certified notifier" or 'certified third-party' we mean the certified individual and the monitoring company whose technology is utilized to conduct monitoring.

[7] The basis for the timing proposed in steps 4 and 5 is to align with what EPA has proposed for operators using similar technology.

operator will provide "no action required" demonstration to EPA as specified in §60.5371b(c)(8) and §60.5371b(e)(1).

   b. If the emissions event was result of component failure or other equipment defect, the operator(s) will complete final repairs **<u>within 15 calendar days</u>** after completing the investigative analysis.

7) All public information should be published by EPA only. EPA should manage all data that is to be public and establish a protocol for when and what type of specific details of a potential super-emitter emissions event is published via EPA's proposed website per §60.5371b(e)(4). We strongly disagree with the assertion in Section IV.C.2.a of the preamble (87 FR 74750) which states "*The EPA would then promptly make such reports available to the public online. Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting.*" Given that much of the data collected can be interpreted incorrectly and not aligned with operating conditions, the EPA should be the only authority to publish data, and EPA should publish data only after operators have had an opportunity to review and respond to the information and EPA has fully reviewed and vetted follow-up actions with the operator.

The timing of each step in the above framework has been crafted with the intent that all participants are held to timelines that are workable and suitable for each step of the framework. Operators are concerned they could receive multiple third-party notifications with limited time and resources to respond appropriately if stricter timing criteria for third parties to provide data is not established. The above framework seeks to address this concern.

1.1.1 EPA should establish transparent certification requirements for third-party monitoring.

Two-way accountability will allow for efficient and effective execution of the super-emitter response program. EPA should develop a clear set of criteria (e.g., in a checklist form) that any certified third-party would need to meet to participate in the program. This certification is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. We appreciate the demonstration for third-party notifiers as outlined in the preamble (87 FR 74750), but do not believe the requirements as proposed in §60.5371b(a) provide enough stringency. Considering the requirements EPA has established for an operator, the same level of scrutiny should also be expected of the third-party data provider when using the same technology. Strict criteria should be established covering the following:

- An expectation from EPA that third parties and their approved detection technologies must be re-certified on a specified frequency. This certification process should be similar to other EPA certifying programs (e.g., EPA auditor).

- An expectation for third parties to attend EPA-specific training, including the do's/don'ts as well as what they are authorized to do or not do – including the handling of data they plan to use within the program.

- Clear criteria for what type of actions may immediately make data collected invalid and/or fully revoke a third party's participation in the program. Regarding EPA's proposed revocation of third party certification (87 FR 74750), we recommend that the criteria for revocation explicitly state that upon a third party's third submission of verifiably false data from any combination of operators or sites, or upon trespass or otherwise unlawful or unauthorized entry to a facility, or vandalizing energy infrastructure, or upon unauthorized distribution or publication of data gathered under the program, the offending third party

shall have their certification revoked for a period of no less than three years. Any data gathered at the time of a trespass would render that data invalid.

1.1.2 The super emitter response program must have a transparent and formal notification process where EPA manages the flow of information from the third-party to the operator.

As similarly done with other EPA programs, formal notification to facility owners/operators (and even with the third-party) could potentially be via email or a central online-based system.[8] The process should allow EPA to confirm that the correct operator received the notification and follow-up if the operator does not respond within a certain timeframe. There are also concerns with measurement of emission events, including pin-pointing sources or facilities correctly (especially when there are adjacent facilities in proximity to each other or sharing boundaries), and in conjunction with the minimum resolution of the monitoring technologies.

Some additional considerations include the following:

- **Operators should be given advanced notice of planned third-party activity. As proposed, the response burden for operators is not predictable and operators are unable to properly plan and schedule resources.** If timing and location of surveys are unknown to a facility owner/operator, operators will have no indication of when and how much resources to have available. This is important to promptly evaluate data and implement corrective action if necessary. Third parties may employ technologies, like aerial surveys which can result in multiple detections in a short amount of time. It's not unreasonable to expect that surveys may be conducted by multiple third parties simultaneously or in series, and conversely, there could be extended periods of no third-party activity. Program requirements must balance the needs of operators to plan for both day-to-day operations and promptly prepare for and respond to third-party activity.

- **Detections of potential super-emitter emission events should be shared with the operator within a certain time period from detection to allow for effective and prompt response to reduce the emission impact.** As proposed, third parties only have to provide data *"as soon as practicable to the owner or operator"* under §60.5371b(b)(7). Since there could be many days between when monitoring occurred and when an operator receives the survey data, an investigative analysis may not find any significant ongoing / persistent emissions event. Furthermore, third-party notifiers could attempt to overwhelm a single operator with a rush of data from multiple monitoring campaigns (e.g., using remote-sensing equipment on aircraft) that would be untenable to fully investigate.

We propose suggested timing for these notifications in Comment 1.1.

1.1.3 Monitoring conducted by a third-party should be pre-approved and accepted by EPA prior to execution of the data gathering event.

There are clear protocols, including monitoring plans, that operators are required to have in place to conduct emission monitoring data. Any certified third party that conducts monitoring must be held to the same stringency

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[8] If an online-based system is chosen, there will be an additional resource / cost burden on EPA to develop and maintain the functionality of the system. Also, there may be an issue when operators are in close proximity to each other and have shared property boundaries, or when a facility was owned by a specific operator at one time but has been sold to another owner.

as an operator if they were to use the same technology. This reciprocity is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. It also is necessary, given that third-party monitoring would create enforceable legal obligations for affected/designated facilities as currently proposed. There is nothing under the law that, in and of itself, prevents any third party from conducting remote monitoring (as noted elsewhere, the law may impose restrictions on where/when/how such monitoring may be done; for example, third-party monitors may not trespass on private property). But when such monitoring has regulatory consequences, it would be arbitrary and fundamentally inconsistent for EPA to set more lenient criteria on third-party monitors than it does for similar monitoring required to be conducted by affected/designated facilities.

At least 30 business days in advance of the planned monitoring campaign, the third-party must submit a monitoring plan to the EPA for approval. The monitoring plan submittal should include the following information (at a minimum):

- Site coordinates and/or map of the area to be monitored;
- Description of monitoring equipment to be used to conduct the activity;
- Documentation of emissions detection limit;
- Proposed starting date and duration of the monitoring activity;
- Contact details (e.g., name, phone number, title) of third-party contact person;
- Name and details of owner of remote monitoring equipment;
- Quality assurance / quality control plan, including calibration procedures, if applicable to the technology (Subsequently, the third-party should also have to demonstrate how it met its monitoring plan for each monitoring event when monitored data is submitted to EPA);
- Specification on how the data will be provided and in what timeframe to the EPA; and
- Certification statement signed by an authorized company official attesting that the third-party will conduct monitoring activities in accordance with EPA requirements.

With the 30-day approval period, it would also allow EPA sufficient time to provide affected facility owners / operators notice of the upcoming monitoring event, which should be provided at a minimum 7 business days prior to the start of the monitoring field event.

1.1.4 There are safety and security concerns with third parties trespassing on private property.

Even though EPA notes in Section IV.C.2.a of the preamble (87 FR 74749) that it considered concerns for the safety of individuals engaged in third-party monitoring and of facility operator personnel, there are still tangible safety concerns related to the use of certain monitoring technology by third parties (e.g., mobile monitoring platforms) to identify super-emitter emissions events. Some operators have experienced public individuals driving through operator sites (especially in remote locations with no “fencing”) with vehicle mounted monitoring devices, which is especially problematic as access can typically be obtained by road, some of which may be private

roads. There have also been issues acknowledged between private third-party landowners and trespassers, which can be another point of contention.

Personnel working at our facilities are required to undergo numerous hours of training to safely perform their work duties, including but not limited to wearing the correct personal protective equipment based on site conditions, exposure to extreme heat or cold weather, biologic hazards such as snakes or other critters, specific training on how to navigate rotating equipment, and where and how to identify hazardous chemicals/gas. For example, training specific to the presence of hydrogen sulfide (H_2S) includes hazards, symptoms of exposure, detection devices, and how to safely walk away from exposure.

Individuals require site specific training to be present at any given facility and there is potential liability (to both the individuals and to company assets) for individuals who do not have this training. The proposed SERP framework is geared to remote technologies, which by their nature should in no way necessitate third-party representatives to appear at facilities. API recommends that any information that is collected by a third party that is outside of an EPA-approved monitoring campaign, where EPA and/or operators have not been notified in advance of the data gathering campaign, be considered invalid. As we also provided in Comment 1.1.1 , trespassing (such as driving through a site) should immediately result in revocation of a third party's certification and render any information gathered at the time invalid.

1.1.5 The EPA should clearly manage how third-party monitored data is published in conjunction with corrective actions taken by operators.

Participation in the regulatory process through the super-emitter response program by EPA-certified third parties must include limitations on the ability of those third parties to use the information gathered under the program for any other purpose. Such limitations must include requirements that the third party (and the monitoring companies they contract) maintain the security and confidentiality of data collected during SERP monitoring, where the monitoring results cannot be independently published (via website or social media). EPA has a fundamental role to play in the validation of third party collected data, which extends to the publication of such data. When a third party accepts the responsibility of participating as a certified notifier, they accept this role and handling of data.

- **Monitored data should not be published without context from operator feedback or corrective actions.** EPA's state within the preamble (87 FR 74750) "*owners and operators would have the opportunity to rebut any information in a notification provided by the qualified third parties in their written report to the EPA, by explaining, where appropriate, that (a) there was a demonstrable error in the third party notification; (b) the emissions event did not occur at a regulated facility; or (c) the emissions event was not the result of malfunctions or abnormal operation that could be mitigated."* While we agree with this concept, the proposed framework does not provide the same level of assurance that these rebuttal statements would be linked to the third-party monitored data directly in the public forum without EPA intervention. If the data is posted on other public websites, there is a chance any resolution/follow up comments and descriptions from operators will not be carried over to the non-EPA sites, therefore resulting in inaccurate presentation of the facts. While we concur that data transparency is valuable, and share the goal of disseminating information to mitigate emissions events, these goals must be balanced with adequate considerations for national security risks, reputational risks (e.g., incorrect operator maligned in media, third party is not approved or certified by EPA, permitted events are taken out of context, etc.), and stakeholder risks.

- **EPA should establish a protocol or annual publication updating on progress of the program.** We believe the current language proposed in §60.5371b(e)(4) establishing a new EPA website is extremely flawed and ambiguous. Third-party monitored data on its own will provide very limited context for the general public and can be easily taken out of context. We believe a synthesized annual report or fact sheet published by EPA would offer a clearer depiction of relevant details with full context around super emitters including but not limited to: how many third-party monitoring events took place, the number and location of valid super emitter emission events that were detected, the number of super emitter events that were permitted or authorized emissions, the rate of erroneous notifications and the types of corrective actions that were taken to repair other super emitter emissions identified. Operator related information could remain anonymous in this annual report, unless EPA found specific operators to be conducting insufficient corrective actions or operators that do not acknowledge EPA's notification attempts regarding the monitoring campaigns (and EPA has verified the correct operator and contact information).

  At a minimum, EPA should limit the information for super-emitter emissions events so that the information cannot be misconstrued or used to publicly attack operators in the media; especially operators who are proactive participants within the SERP. The shared goal of finding these leaks and fixing them as expeditiously as possible should remain at the forefront and in conjunction with transparency objectives.

1.1.6 An "investigative" analysis should be conducted in conjunction with initial corrective actions.

As we explain further in Comment 3.2, the EPA outlines in §60.5371b(c) specific actions to take place if a super-emitter emission event occurs. API supports investigating the source and cause(s) of significant emissions events that are brought to an operator's attention Through the process described in our comments. We agree that EPA's investigative actions listed §60.5371b(c) are appropriate and practicable as far as investigating and conducting initial corrective actions for super emitter events. However, EPA's use of the term "root cause analysis" is problematic and ambiguous. The concept of "root cause analysis" is embedded in numerous other regulatory and non-regulatory programs and has varied meaning and purpose in each application. Thus, use of that term here does not clearly and adequately define the scope of the legal obligation, which will make it difficult for operators to understand what must be done to comply and will invite dispute and controversy if/when this program is implemented. To address this concern, we recommend the actions EPA has outlined be maintained, but the term supplied as the definition for those actions be changed to "investigative analysis" as it relates to super-emitters in §60.5371b(c).

1.1.7 After an investigative analysis has occurred, an operator should have the ability to designate the emission event as "no action required," as applicable.

Since the source of an emission detection during a monitoring campaign could be the result of various situations (and even EPA acknowledges that there may be demonstrable errored data), API suggests that the EPA include a pathway for operators to simply identify situations where "no corrective action required" beyond what has been proposed in §60.5371b(e)(1). These additional situations could include 1) the wrong operator was notified; 2) where the emission event cannot be validated by the operator; 3) there was a demonstrable error in the third-party notification; (4) the emission event did not occur at a regulated facility (e.g., well site or compressor station); or 5) the emission event was authorized as authorized or permitted operations. The information an operator should submit back to EPA should be simplified for planned or authorized emissions. Further, within

§60.5371b(e)(1)(iii), EPA must clarify that the applicable standard is limited to the applicable standard of this subpart.

1.1.8 Safe Harbor for Operators

The presence of a super emitter emission event does not necessarily indicate a standard has been exceeded or that a violation has occurred. Moreover, any documents shared with EPA articulating corrective actions taken should be subject to a safe harbor provision that prevents EPA or any other entity from using the information in the document for purposes of enforcement / notice of violation (NOV), civil suit, etc.

1.1.9 The role of states as a delegated authority within the super emitter proposed framework is unclear.

Throughout the preamble EPA uses language that mentions state agencies as delegated authorities. One such example is found at 87 FR 74750, *"The EPA further proposes that the entity making the report shall provide a complete copy to the EPA and to any delegated state authority (including states implementing a state plan) at an address those agencies shall specify."* The role of state agencies within the SERP must be more adequately defined. For example, as explained in these comments, the SERP program is not lawful or practically workable unless EPA takes a direct role in implementing the program (e.g., EPA must review and approve site-specific third-party monitoring plans, EPA must receive and vet the results of third-party monitoring and must decide whether the results are actionable). In the final rule, EPA must explain the process and degree to which these functions may reasonably be delegated to the states and, for functions that EPA determines are delegable, provide mechanisms to assure consistency among EPA's and the delegated states' programs.

2.0 Fugitive Emissions at Well Sites, Central Production Facilities and Compressor Stations

API supports the retention of NSPS OOOOa requirements for optical gas imaging (OGI) monitoring at well sites, central production facilities, and compressor stations. Except for multi-wellhead only well sites (see Comment 2.1), API also supports the proposed audio, visual, and olfactory (AVO) and OGI monitoring frequencies. In addition to the following comments concerning requirements for fugitive emissions at well sites, central production facilities, and compressor stations, API notes that EPA is not providing a meaningful opportunity to comment on a key basis for removing the wellhead only exemption because the underlying data for the Department of Energy (DOE) study[9] is unavailable.

2.1 API proposes AVO inspections only for all wellhead only sites.

EPA's focus on finding large fugitive emissions at single wellhead only sites using AVO inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. As EPA has already concluded, AVO inspections are a useful tool at

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[9] Bowers, Richard L. Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859

sites that lack extensive background noise and have field gas containing mixtures of methane and VOCs and condensate or produced liquids (87 FR 74727)[10]. Not only do wellhead only sites match these criteria, but their emission points are closer to ground level compared to other sites. For these reasons, out of all well site configurations, AVO is expected to perform the best at wellhead only sites, and it generally can be applied more frequently than other leak detection methods. EPA appropriately concluded that *"the types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspection"* (87 FR 74729)[11]. Given the large number of wellhead only sites and EPA's focus in regulating fugitive emissions at these sites, quarterly AVO inspections are appropriate to detect fugitive emissions at any wellhead only site including single wellhead or multi-wellhead well sites.

The proposed leak detection method and frequency for any emission source should take into consideration the count and relative magnitude of emissions, among other factors. The number of wellhead only sites across the U.S. is estimated to be in the tens of thousands. The resource demand from any leak detection requirement on wellhead only sites using OGI or Method 21 quickly multiplies.

EPA notes that the DOE study "*demonstrates that fugitive emissions do occur from wellheads, and in some cases can be significant"* as the basis for regulating wellheads. Similarly, commenters indicated "the wellhead itself is a source of emissions" because "these well sites have other smaller equipment that leaks and malfunctions, with large emissions having been observed from these sites". While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall well site emissions. A study conducted over the Permian Basin determined that simple sites, such as wellhead only sites, experience median emission rates two orders of magnitude smaller than complex sites (0.03 kg/hr for simple sites vs 2.6 kg/hr for complex sites)[12]. CAMS contracted with Bridger Photonics to conduct aerial surveys performed in the Permian Basin (5,361 pieces of equipment on 1,450 facilities over 250 square miles). The project found that 2% of total detected emissions were from wells and 5% of total detections were from wells[13].

These studies demonstrate that the population average emissions from wellheads is not relatively significant and therefore chasing fugitive leaks from these sources will not be impactful compared to deploying resources to other contributing sources. Nevertheless, we recognize this does not preclude the potential for fugitive emissions from an individual wellhead. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Coupled with proposed requirements[14] for conversion to non-emitting pneumatic controllers at existing sites, the increased cost of additional OGI screening at these sites raises further concerns regarding premature shut-in of production and states' ability to preserve the remaining useful life of facilities.

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[10] On the other hand, AVO inspections are a useful tool for identifying when there are indications of a potential leak without the need for expensive equipment or specialized training of operators. For example, at sites that lack extensive background noise, a person would be able to hear if a high-pressure leak is present, which could present as a hissing sound. Field gas produced at well sites contains a mixture of methane and various VOCs, which have the potential to be detected by smell. Where the field gas contains a lot of condensate or other produced liquids, any resulting leaks would present as indications of liquids dripping or potentially puddles forming on the ground.

[11] The types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspections and would not require the use of OGI for identification. Therefore, the EPA evaluated a periodic AVO inspection and repair program for addressing fugitive emissions from single wellhead only well sites.

[12] Robertson, Anna M., 2020, New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, Environmental Science and Technology, 54(21), 13926-13934 https://pubs.acs.org/doi/10.1021/acs.est.0c02927

[13] https://methanecollaboratory.com/wp-content/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021_vFinal.pdf

[14] See Comment 7.0

EPA's basis for applying OGI to multi-wellhead only sites is centered around additional connection points and valves with generally smaller emissions (87 FR 74732)[15]. While this basis is true, the focus appears to be misguided. If the principal concern with a single wellhead only site is to find the rare, but possible, large emissions leak, then it should follow that the principal concern for a multi-wellhead only sites should also be the rare occurrence of large emission leaks because it is relatively more likely with more than one well-head. That is, what warrants more attention to a multi-wellhead only site should not be the potential for more small emission leaks, but the greater potential for a large emission leak. Any significant difference in emissions leak potential from a single wellhead only site versus a multi-wellhead only site is not likely to be because of a small emission leak.

More frequent monitoring may also be challenging since many existing wellhead only sites can only be reached on foot due to remote location and lack of lease road access. While we believe quarterly AVO is the appropriate frequency for all wellhead only sites, at a minimum, bimonthly AVO inspections only would also be acceptable as the monitoring requirement for multi-wellhead only sites.

2.2 The proposed definition of fugitive emissions component requires further clarification.

Several aspects of EPA's proposed definition of fugitive emissions component require further clarification.

- **In yard piping should not be included in the definition of fugitive emissions component.** The inclusion of in yard piping as a fugitive emissions component expands that definition in unprecedented ways. Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.[16]
- **Definition should include thief hatches or other openings on a controlled storage vessel only.** Monitoring thief hatches and other openings on uncontrolled storage vessels adds no environmental benefit since the storage vessel emissions will be the same whether they are emitted from the tank vent or through thief hatches or other openings. Combined with the next item, fugitive emissions component should include thief hatches or other openings on a controlled storage vessel that is not subject to NSPS OOOO, OOOOa, or OOOOb because of a construction/reconstruction/modification date on or before August 23, 2011, or a legally and practicably enforceable limit.
- **Definition should also include the appropriate references to NSPS OOOO and OOOOa.** As proposed, fugitive emission components include covers and closed vent systems and openings on storage vessels not subject to NSPS OOOOb requirements. Since EG OOOOc will be implemented over the coming years, the definition of fugitive emissions component should also include the appropriate reference to

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[15] Multi-wellhead only well sites. For wellhead only well sites with two or more wellheads, the EPA anticipates that the same large emissions source (i.e., surface casing valves) would be present. In addition to these valves on the wellheads have additional piping, and thus connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO.

[16] We note that EPA's rationale for adding yard piping to the definition of "fugitive emissions component" is that, "[w]hile not common, pipes can experience cracks or holes, which can lead to fugitive emissions." 87 Fed. Reg. at 74723. EPA explains that its proposal will "ensure that when fugitive emissions are found from the pipe itself that necessary repairs are completed accordingly." Id. EPA's proposal is vague and fails to provide an adequate opportunity to formulate meaningful comments because EPA does not explain how leak detection should be accomplished for "yard piping" as compared to other already-listed fugitive emissions components, where there are identifiable leak points (such as valve stems or flange interfaces) that are the target of monitoring. For example Section 8.3 of Method 21 (which applies to LDAR standards such as the one here that specify a concentration-based leak definition) explains that monitoring should be conducted "at the surface of the component interface where leakage could occur." Section 8.3 also includes detailed instructions for individual components (such as valves), where particular leak points are identified. In contract, there is no identifiable leak point for "yard piping" that reasonably would be the target of monitoring. In fact, using Method 21, there is no obvious way that the required monitoring could be conducted because of the expansive lengths of pipe where the sort of leaks that EPA seems to be concerned about might occur. Before finalizing a requirement to include yard piping in the definition of fugitive leak component, EPA must provide additional explanation of how the LDAR provisions would apply and provide an opportunity for public comment on that necessarily more specific proposal.

NSPS OOOO and OOOOa requirements. For that time period, a site could have storage vessels subject to NSPS OOOO or OOOOa and be subject to NSPS OOOOb fugitive monitoring. See Comment 12.5 regarding the proposed reconciliation of NSPS OOOO and OOOOa with NSPS OOOOb and EG OOOOc.

- **Existing clarifying language from NSPS OOOOa should be retained.** Since NSPS OOOOb proposes to allow natural gas-driven pneumatic controllers and pumps in limited circumstances (e.g., sites in Alaska without access to electric power), the existing language from the NSPS OOOOa definition should be retained to clarify what is considered fugitive emissions.

Based on the above clarifications, API offers the following suggested redline, which retains much of the current NSPS OOOOa definition, to the proposed definition of fugitive emissions component in NSPS OOOOb and EG OOOOc:

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411, §60.5411a, or §60.5411b, thief hatches or other openings on a controlled storage vessel not subject to §60.5395, §60.5395a, or §60.5395b, compressors, instruments, and meters~~, and in yard piping~~. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

2.3 Delay of repair requirements should be expanded.

Due to the hundreds of thousands of sites that would be subject to fugitive monitoring under NSPS OOOOb and EG OOOOc, EPA should expand the proposed delay of repair requirements in the following ways:

- **Consistent with the requirements for natural gas processing plants, EPA should allow for delay of repair due to parts unavailability.** NSPS VVa, incorporated by reference in NSPS OOOO and OOOOa for gas plants, allows for delay of repair beyond a unit shutdown if "*valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.*"[17] In the Preamble to the November 2021 Proposal[18], EPA recognized that operators of older equipment may experience delays in obtaining replacement parts. Given current supply chain issues and the larger number of well sites, centralized production facilities, and compressor stations, EPA should expand the current delay of repair requirements to include delays because of parts unavailability.
- **EPA should add other potential circumstances beyond an operator's control that would require a delay of repair.** Repairs may be delayed due to circumstances not currently listed in the rule. Specifically, there are seasonal constraints related to farming and/or endangered species where operators cannot bring a rig in or have surface disturbance. Delay of repair should be allowed for these unique situations.

Based on these items, API offers the following suggested redlines to §60.5397b(h)(3), which are based on existing regulatory language from NSPS VVa:

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[17] 40 CFR §60.482-9a(e)

[18] 86 FR 63174

(3) Delay of repair will be allowed:

(i) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel~~.~~;

(ii) If the necessary replacement part supplies have depleted and supplies had been sufficiently stocked before supplies were depleted, the repair must be completed as soon practicable, but no later than 30 days once the necessary replacement part supplies are available; or

(iii) If the necessary repair equipment cannot be brought to the site for reasons, such as lease restrictions for farming or seasons for endangered species, the repair must be completed as soon practicable, but no later than 30 days once repair equipment may be brought to the site.

2.4 Repair timelines should be consistent for leaks identified using AVO or OGI.

The repair timelines should be the same whether the fugitive emissions at well sites, centralized production facilities, and compressor stations are identified using AVO, OGI, or Method 21 because the necessary repair actions are agnostic to the detection method. In other words, operators should have the same time to make repairs regardless of leak detection method because the repair actions depend more on the leaking component rather than detection method.

EPA's stated reason for requiring shorter repair timelines is *"so that the monthly AVO inspections do not overlap the repair schedule"*[19]. This justification is insufficient for two reasons:

- As proposed, monthly AVO inspections would apply only to compressor stations. This overlap would not occur for bimonthly or quarterly AVO inspections at well sites and centralized production facilities.
- EPA has allowed repair timelines to overlap with inspection in other regulations. Under existing LDAR regulations, a component may be on delay of repair for multiple monitoring periods in certain circumstances.

While AVO is generally more effective at detecting larger emissions, the existing OGI repair timelines do not consider emission rate because OGI cannot quantify the leak rate. The same inability to quantify fugitive emissions also applies to AVO, and so EPA should have the same repair timelines for both detection methods. Finally, consistent timelines would also streamline compliance.

To address this concern, API offers the following suggested redline of §60.5397b(h):

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[19] 87 FR 74737

Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made ~~in accordance with paragraphs (h)(1)(i) and (ii) of this section.~~

~~(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using visual, audible, or olfactory inspection.~~

~~(ii) If you are complying with paragraph (g)(1)(i) through (iv) of this section, a first attempt at repair shall be made~~ no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than ~~15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and~~ 30 calendar days after the first attempt at repair ~~as required in paragraph (h)(1)(ii) of this section.~~

2.5 EPA should clarify depressurized equipment are exempt from fugitive emissions monitoring.

State rules, including New Mexico[20] and Colorado[21], exempt depressurized equipment[22] from fugitive emissions monitoring because leak surveys are not anticipated to result in emissions reductions at these facilities. Monitoring would resume once the site or equipment is back in service. EPA should provide a clear exclusion for these types of facilities or equipment under both NSPS OOOOb and EG OOOOc. One suggestion would be to model the regulatory language on the existing storage vessel out of service and return service requirements.

See also Comment 13.3.

2.6 Additional clarification is needed for the proposed definition of modification for a centralized production facility.

EPA's proposed definition of modification for the collection of fugitive emissions components at a centralized production facility presents a challenge since the operator of a centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility especially when the operator differs between the centralized production facility and the offsite wells that send production to it. The operator of the centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility since the upstream operator is typically only required to notify the centralized production facility operator when a new well is drilled and starts to send production to the gathering system. The upstream operator may not necessarily identify the specific centralized production facility. EPA may not have anticipated this scenario in proposing the definition of modification for the collection of fugitive emissions components at a centralized production facility.

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[20] 20.2.50.116.C(9) NMAC

[21] https://drive.google.com/file/d/1a3IJ74txUxJ241wgh-ZMRx0Rn7LV3z2V/view

[22] The CO regulations reference depressurized equipment, while the NM regulation references temporarily abandoned wells.

To address this concern, API suggests that the modification criteria for centralized production facilities be limited to "An increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility". This criterion is simple, clear, and aligned with the purpose and definition of a centralized production facility, which is to gather hydrocarbon liquid production into storage vessels. As such, API offers the following suggested redline of §60.5365b(i)(2):

> *For purposes of §60.5397b and §60.5398b, a "modification" to centralized production facility occurs when~~:~~ an increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility.*
>
> ~~*(i) Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;*~~
>
> ~~*(ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or*~~
>
> ~~*(iii) A well site subject to the requirements of §60.5397b or §60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.*~~

We also suggest EPA add clarification to the definition for central production facility that addresses custody transfer.

2.7 EPA's proposed well closure plan requirements present several technical and legal issues.

After reviewing EPA's proposed well closure plan requirements, API has identified the following technical and legal issues:

- **The proposed well closure plan requirements are duplicative with other regulations.** Well closure requirements are within the jurisdiction of State Oil & Gas Commissions and other agencies, not the EPA. Under state law, a well is required to be plugged and abandoned when it has reached the end of its useful life. In all States, operators must provide written notice of plugging and comply with regulatory requirements to plug and abandon the well, including removing equipment, setting downhole plugs, cementing in the casing, capping the well to prevent fluid migration and restoring the surface site. These practices are done to permanently confine oil, gas and water into the strata in which they were originally found. For wells located on federal lands, separate BLM requirements also apply for well closure. Depending on the well location (e.g., located in an area with potash mining), additional requirements may also apply. For some wells, EPA would be adding a fourth set of well closure requirements.

  Therefore, EPA's proposed notifications and well closure plan requirements are duplicative, unnecessary, and increase administrative burden while providing no discernible accompanying environmental benefit when an operator is working to properly close a well. In certain cases when an emergency plugging is required, the proposed notification timelines may be impossible to meet.

- **EPA does not have the technical expertise to review well closure plans.** State Oil & Gas Commissions have the technical knowledge to evaluate well closure plans, because they have the jurisdiction for well closure. Without the technical knowledge, EPA's proposed well closure plan requirements require

significant operator and agency resources but provide no additional environmental benefit. Operators should only be required to maintain records of an approved well closure plan by the state authority with jurisdiction; these records could be provided to EPA upon request.

Under existing State and BLM requirements, well closure plans include detailed information on the well casing, tubing, and rod dimensions, perforation depths, proposed plug materials, depths, tagging, and verification, leak testing for cast iron bridge plug (CIBP), and other required data.

- **EPA does not have authority under CAA § 111 to impose financial assurance requirements.** Part of the proposed well closure plan is a “description of the financial requirements and disclosure of financial assurance to complete closure”. This requirement is clearly beyond EPA’s authority under the Clean Air Act (CAA). For more details, refer to Comment 12.8.

- **The proposed requirements may create unforeseen liability consequences.** EPA has not clarified how the proposed well closure requirements will transfer with ownership. Under State and BLM rules, chain of title is defined. EPA should not create duplicative requirements that could create potential liability consequences for operators.

- **The notification prior to well closure should be removed. If EPA finalizes the proposed well closure requirements, EPA must clarify when a well closure plan is required to be submitted.** Language at §60.5397b(l) potentially conflicts with §60.5420b(a)(4) in terms of whether a well closure plan needs to be submitted every time that production ceases for more 30 days or only when the operator intends to close the well and stop fugitive emission monitoring. “Cessation of production” is not defined in the proposed regulations. A 30-day period from cessation of production is not indicative of well closure. Operators may have many instances where wells are shut-in for periods of 30 days or more, with complete intent to return the wells to production. A few examples include a facility undergoing maintenance or repair, shut-in for offset fracturing, lack of access to gathering, or wells on cycled production. We request EPA clarify that the well closure plan requirements and notification only when operators intend to permanently close the well and stop fugitive monitoring.

Overall, API recommends that requirements within NSPS OOOOb and EG OOOOc pertaining to well closure be limited to the following:

- **A recordkeeping requirement to maintain records of an approved well closure plan by the local authority with jurisdiction.** This recordkeeping only requirement would avoid unnecessary and duplicative requirements with State Oil and Gas Commissions. The records could be submitted to EPA upon request.

- **A final OGI survey to confirm no detected fugitive emissions after well closure.** EPA could still require a final OGI survey after well closure.

3.0 Alternative Leak Detection Technologies including Periodic Screening and Continuous Monitoring

API recognizes and appreciates EPA’s initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA

to make key adjustments in the final rules to enhance the use of these technologies and to not unintentionally disincentivize development and deployment of these technologies. Making alternative technologies more accessible in these rules can also have synergistic benefits with measurement-informed inventory goals in related rulemaking such as the Inflation Reduction Act's Methane Emissions Reduction Program and EPA's Greenhouse Gas Reporting Program.

These adjustments are described in our comments below, including initial comments on EPA's FEAST modeling. While API is exploring additional modeling analyses, due to the short comment period, any additional modeling analysis may be provided in a subsequent submittal. We welcome the opportunity for future discussions on this important topic with EPA staff.

3.1 Comments Regarding Both Periodic Screening and Continuous Monitoring Technologies

3.1.1 Technologies should be available for use upon finalization of NSPS OOOOb and EG OOOOc.

To facilitate adoption of alternative leak detection technologies, operators need options available beginning with finalization of the proposed rules. EPA's proposed 270-day review timeline means that technologies would likely not be approved until after the first AVO, OGI, or Method 21 inspection, since the initial inspection would be required 90 days after NSPS OOOOb is finalized. This gap may disincentive the use of alternative technologies as operators would already be required to implement the standard fugitive emissions monitoring program with AVO, OGI, and/or Method 21 inspections.

Recognizing that EPA is unable to approve technologies until the rules are finalized, API proposes that alternative technology applications be granted conditional approval if they are submitted within 90 days after the final rule is published in the Federal Register (based on the proposed timelines for the initial AVO, OGI, or Method 21 surveys). This initial conditional approval period would allow for the immediate use of those alternative technologies to achieve initial compliance with NSPS OOOOb. An alternative to initial conditional approval could be extending the deadline for initial monitoring surveys from 90 day to one (1) year in §60.5397b(f) and §60.5398b(b)(2). Time beyond the 270-day conditional approval would be needed for operators to contract with vendors and conduct the initial surveys.

Operators would be able to use the conditionally approved technologies until EPA provides written disapproval to the requestor. Disapproval of a conditionally approved technology should not be considered a deviation for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology. EPA has already proposed the idea of conditional approval for alternative technologies, so this idea could be extended to allow for technologies to be available for initial compliance. EPA could also utilize technologies approved by a state or another country (e.g., Colorado or Canada) as a starting point for initial conditional approval.

In place of or in addition to initial conditional approval, API recommends that EPA prioritize review of initial alternative technology applications (submitted within 90 days after final rule is published in Federal Register) based on the following criteria:

- The technology is already approved for use by a state or another country. Approval by another agency means that the technology has been reviewed previously and is likely to meet EPA's proposed minimum detection threshold of ≤ 30 kg/hr (based on a probability of detection of 90%) as shown in Table 1 and Table 2 to NSPS OOOOb.

- The technology is already used by one or more operators for monitoring under voluntary efforts or regulatory programs. One potential measure could be the number of sites monitored in 2022 using the alternative technology under voluntary efforts or other regulatory programs.

An initial conditional approval period and prioritization of review would allow for quicker adoption of alternative technologies and would also alleviate pressure from EPA to review a potential influx of applications upon rule finalization. Without these measures, EPA could be overwhelmed with applications, and the full 270-day review period would pass before the first technologies would be conditionally approved.

3.1.2 EPA should clarify how the review and conditional approval process will be implemented.

We request EPA provide the following clarifications regarding the application review and conditional approval process for use of alternate technologies:

- EPA should clarify that operators are able to use conditionally approved technologies until EPA provides written disapproval to the applicant.
- EPA needs to consider how to effectively notify operators when a conditionally approved technology is disapproved.
- EPA should also clarify that disapproval of a conditionally approved technology should not affect compliance for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology.

EPA should also elaborate on how deficiencies in an application will affect the proposed review timelines. For the initial 90-day review and final 270-day review, the proposed regulatory language implies that deficiencies in an application will result in disapproval and require the applicant to revise its request and restart this process. As with other application processes, agencies will typically issue requests for additional information with appropriate deadlines so that applicants can resolve deficiencies without restarting the entire application process. Forcing applicants to restart the process for any application deficiency would further delay the approval of alternative technologies for use by operators.

3.1.3 Emissions detected from covers and closed vents systems using alternative technology or while doing required follow-up surveys do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

As discussed in more detail in Comment 5.1 , emissions detected from covers and closed vent systems are not necessarily violations of the "no identifiable emissions" standard since it is a work practice standard rather than a numerical zero emission standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through alternative technology or a required follow-up survey triggers the

obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented. Treating emissions detected from covers and closed vent systems as violations not only fails to acknowledge technical reality contrary to best system of emission reduction (BSER), but it also disincentivizes the use of alternative technology.

3.1.4 While API appreciates EPA providing modeling, EPA's current model overestimates the effectiveness of AVO and OGI.

We appreciate EPA's efforts to create a technology-agnostic, performance-based alternative test method framework supported by an underlying, publicly available FEAST model. In EPA's model, the probability of detection curves for AVO and OGI have 100% probability of detection for leaks above approximately 200 g/hr and 60 g/hr, respectively. While these are useful detection methods in various applications, these characterizations overestimate their effectiveness in certain field conditions and leads to impractical performance standards for the alternative technologies as discussed further in Comment 3.3.1 for periodic screening and Comment 3.4.5 for continuous monitoring.

For example, AVO inspections are less likely to find large leaks if they are located above the person performing the inspection, they occur in areas that the person cannot enter due to safety concerns (e.g., potential for H_2S exposure), or they are located in areas with high noise among other reasons. While 60 g/hr is the current NSPS OOOOa and proposed NSPS OOOOb and EG OOOOc standard for OGI cameras, probability of detection for OGI also depends on the camera operator and field conditions.[23] A more realistic characterization of AVO and OGI detection methods would create a more realistic equivalency model for alternative technologies. Due to the short comment period, we may continue to analyze EPA's assumptions about intermittency of leaks, model plant configurations (i.e., equipment types and component counts), and leak occurrence in subsequent comments.

3.1.5 The alternative technology framework should allow flexibility in conducting leak surveys due to seasonal challenges.

The alternative technology framework should allow for flexibility in conducting AVO/OGI and screening surveys due to seasonal challenges and weather events. Some examples include but are not limited to:

- Snow cover can adversely affect the ability of some alternative technologies to detect methane during part of the year.
- High winds can also prevent aerial-based technologies from being deployed on certain days.
- Weather events such as hurricanes may limit the ability to deploy OGI camera operators to sites for surveys.

The alternative technology framework should allow different technologies to be deployed at appropriate frequencies throughout the year. The deadline for the next survey would be based on the type of site and the last survey conducted. As an example, at single wellhead only site, an operator could conduct AVO inspections for the first two quarters of the year followed by a screening survey at ≤ 2 kg/hr and then another AVO inspection no later than four months after the screening survey, based on EPA's proposed requirements. Flexibility in applying alternate screening technologies should include provisions that use of a different technology than originally

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[23] Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. *Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions*. Environmental Science & Technology 2020 54 (18), 11506-11514 DOI: 10.1021/acs.est.0c01285

planned (due to weather or other external factors) constitutes an allowance, not a deviation from an operator's monitoring plan.

3.1.6 Framework for alternative leak detection technologies should allow multiple technologies, including satellite, to be combined. More combinations of technologies should be added to the proposed periodic screening matrices.

Overall, API believes that allowing the use of a combination of alternative leak detection technologies can be effective to find and fix leaks. This alternative approach recognizes that each leak detection technology (AVO, OGI, Method 21, periodic screening, or continuous monitoring) has strengths and weaknesses in terms of detection threshold, proximity to the source, localization performance, deployment frequency, and costs. For example, ground-based OGI has a low detection threshold and localizes the leak to a particular component but requires proximity to the source and is infeasible to deploy at higher frequencies. Whereas satellites, aerial and continuous technologies can be deployed more frequently than ground-based OGI, the increased distance from the source may not detect leaks on the component level. With these remote detection technologies, resources can be deployed more efficiently to repair leaks – operators would only need to visit sites with detected emissions to make repairs whereas using only OGI surveys require operators to visit each site but could result in no detected emissions. A continuous monitoring system can quickly detect a leak and depending on sensor location, provide an approximate location, but may not fully visualize its location like a plume map from a satellite or aerial survey. In other words, no individual leak detection technology offers a perfect solution.

By allowing the option for a combination of these various technologies into a single monitoring plan or framework, the weaknesses of one technology can be offset by the strengths of another, and the selected technologies work together to improve leak detection and reduce emissions in a flexible and cost-effective manner. Technologies can be combined such that larger emissions are quickly detected, and technologies that detect smaller emissions are deployed less frequently. Finding and fixing the biggest leaks quickly can greatly impact the overall emission reductions.

A multi-layered approach for leak detection combines various technologies to achieve greater emission reductions. Some fugitive emissions may be detected with traditional OGI or AVO during regular LDAR inspections. Intermittent emissions are not always detected during OGI or AVO inspections; however, they may be detected by a continuous monitoring system. Deploying continuous monitors is not an option for all sites, such as those without access to reliable grid power. Alternatively, an aerial survey may detect emissions from such sites over a large area. Although satellites cannot always detect emissions at the component level, they can be useful for basin-wide detection of large emissions that may occur outside of scheduled inspections. This concept of layering various leak detection technologies is illustrated in the graphic below where lines and layers represent strengths of a given technology while the dashed circles represent weaknesses allowing undetected emissions. An example of this multi-layered approach using data from the Permian Basin can be found in an industry pre-publication paper[24].

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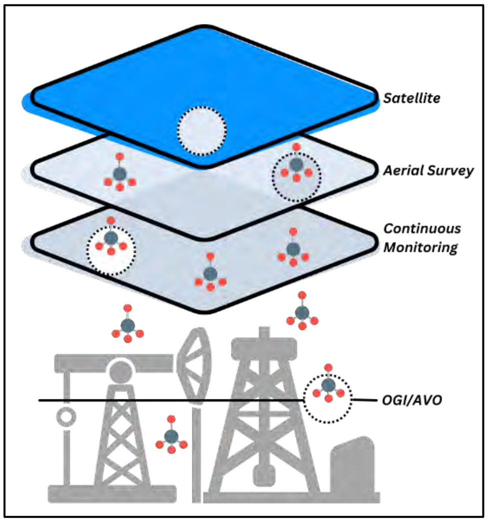
[24] Cardoso-Saldaña FJ. *Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities*. ChemRxiv. Cambridge: Cambridge Open Engage; 2022; This content is a preprint and has not been peer-reviewed. DOI: 10.26434/chemrxiv-2022-f7dfv

Figure 1. Multi-layered Approach for Leak Detection



EPA has already included the idea of layering technologies with the screening survey plus annual OGI survey options in the periodic screening matrices. API has two specific suggestions regarding an alternative multi-layered approach for leak detection:

- **API recommends that continuous monitoring (see also Comment 3.4.1) and satellite technology be included as options directly in the matrices in combination with the periodic survey with and without annual OGI.** In other words, combinations like "Quarterly + Weekly Satellite + Annual OGI", "Quarterly + Weekly Satellite", "Quarterly + Continuous + Annual OGI", and "Quarterly + Continuous" should be modeled and added to the periodic screening matrices with appropriate detection thresholds for the screening technology. Satellite technology would be defined with a ≤ 100 kg/hr detection threshold and a weekly frequency. Having frequent satellite surveys will allow reducing the number of periodic surveys per year for a given detection threshold with and without an annual OGI survey.

- **Separately, we would also welcome an additional optional and flexible framework independent from the periodic screening matrices and case-by-case AMEL process where an operator can develop a monitoring plan for each basin/site with their chosen suite of EPA-approved technologies via EPA-approved modeling.** Similar to EPA's proposed clearinghouse approach to approving alternative screening technologies, EPA could evaluate and approve different modeling platforms for use in developing monitoring plans. Modeling could be refined over time based on data generated through the monitoring plan. The initial modeling should represent the highest emissions level since emissions should decrease over time as NSPS OOOOb and EG OOOOc are implemented over the next several years. This approach would both allow the technology to mature over time and a streamlined approach to alternative modeling compared to the existing case-by-case AMEL process.

  This flexible framework gives operators a clear pathway for a custom, fit-for-purpose option and would be an alternative to both the AVO/OGI requirements and alternative technology requirements. To benefit smaller operators, EPA should consider both a conservative, and realistic, default plan that allows for flexibility in monitoring technology as well as an option where an approved monitoring plan can be used by other operators with similar assets.

3.1.7 Repair timelines should be consistent for leaks using AVO/OGI or alternative leak detection technologies.

Recognizing that repair timelines are part of the overall effectiveness of a leak detection program, API recommends that repair timelines be consistent between traditional (AVO, OGI, or Method 21) and alternative (periodic screening or continuous) leak detection programs. Repair actions depend more on the leaking component rather than detection method. The proposed repair or corrective action timelines in §60.5398b(b)(4) for periodic screening and §60.5398b(c)(6) for continuous monitoring are shorter than those in §60.5397b(h) for fugitive emissions components and §60.5416b(b)(4) for covers and closed vent systems. The shorter repair timelines for alternative leak detection technologies may disincentivize their use. Consistent repair or corrective action timelines would streamline compliance and facilitate the use of multiple technologies. If EPA chooses to finalize shorter repair timelines for alternative technology, API recommends that repairs be prioritized based on higher detected emissions.

3.1.8 EPA should allow operators to use alternative technology to comply with NSPS OOOOa without an AMEL.

Since the proposed NSPS OOOOb fugitive monitoring requirements including alternative technology are at least as stringent as the existing NSPS OOOOa requirements, EPA should allow operators use of alternative technology for NSPS OOOOa compliance without going through the Alternative Means of Emission Limitations (AMEL) process or waiting for state plans to be fully implemented under EG OOOOc. Both the AMEL process and EG OOOOc state plan implementation could take years. EPA can make the NSPS OOOOb alternative technology a compliance alternative for NSPS OOOOa since EPA is planning to update certain aspects of NSPS OOOOa in conjunction with this rulemaking. This addition should not require further notice since the requirements are at least as stringent as the existing NSPS OOOOa requirements. Some alternative technology (e.g., aerial surveys) is deployed over a particular basin or portion thereof and could include both NSPS OOOOa and OOOOb sites. Therefore, allowing the use of alternative technologies for NSPS OOOOa compliance without an AMEL would further incentivize the adoption of these emerging technologies.

3.2 The term “investigative analysis” should replace “root cause analysis”.

The specific term “root cause analysis” has other meanings and specific denotations in various regulations and in the oil and gas industry. There is also a legal issue with how this term can be interpreted in any legal or enforcement proceedings, as well as how it could obligate operators to actions or additional requirements that are not necessarily included within this proposed rule.

API understands and supports EPA’s intent for investigating why certain emission events or leaks have occurred, but recommends the removal of the term “root cause analysis” and replacement with the term “investigative analysis” within NSPS OOOOb and EG OOOOc.

We offer additional comments specific to how “root cause analysis” has been proposed with respect to the super-emitter response program in Comment 1.1.6.

3.3 Comments Specific to Periodic Screening Technology

3.3.1 Proposed periodic screening matrices do not incentivize the use of the alternative technology.

While API acknowledges EPA's proposed matrices of minimum detection thresholds and frequencies, they do not incentivize the use of alternative technology as proposed. To have the same monitoring frequency as OGI, alternative technology must have a minimum detection threshold of ≤ 1 kg/hr for both quarterly OGI and semiannual OGI requirements. This proposed performance level effectively limits the alternative technology options as operators are more likely to use technology with the same or less frequent monitoring than OGI. The proposed performance standards in the matrices are more stringent than needed in part because EPA's FEAST model overestimates the effectiveness of AVO and OGI inspections as mentioned previously in Comment 3.1.4. To incentivize the use of alternative technologies, API believes that quarterly screening surveys with an annual OGI survey should equate to a minimum detection threshold of ≤ 10 kg/hr for sites subject to quarterly OGI; the rest of the matrices would be adjusted accordingly. Supporting modeling analysis may be provided in subsequent comments.

These matrices also do not appear to be based primarily on the minimum leak detection threshold. In proposed Table 1 to Subpart OOOOb of Part 60, the minimum detection threshold is proportional to screening frequency between monthly and bimonthly frequencies without annual OGI (i.e., minimum detection threshold is halved for twice as frequent monitoring). However, if an annual OGI survey is included with monthly and bimonthly screening surveys, the minimum detection threshold is decreased by a factor of 3 instead of the expected 2 (i.e., monthly + annual OGI requires 30 kg/hr detection while bimonthly + annual OGI requires 10 kg/hr instead of the expected 20 kg/hr). While frequency and detection threshold are not the only parts of a leak detection program, one would expect frequency and detection thresholds to be roughly proportional assuming that other aspects of the leak detection program (e.g., repair timelines) are constant.

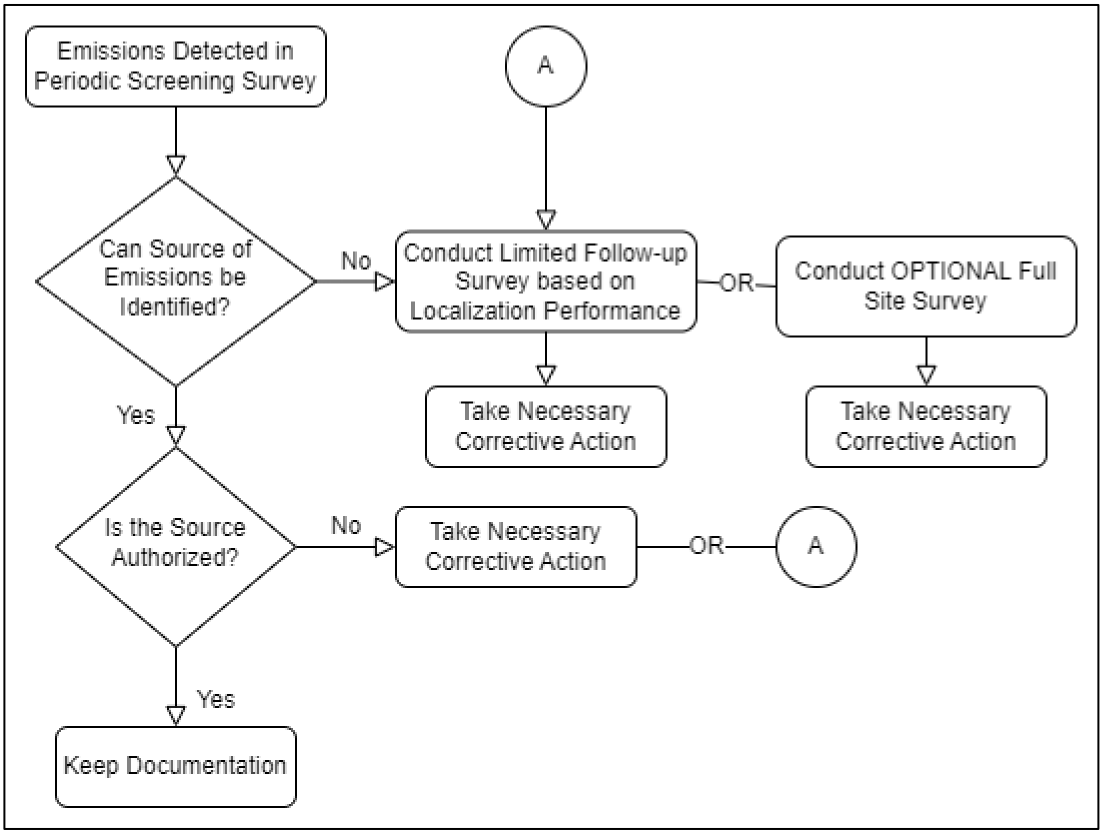
3.3.2 Proposed follow-up actions for periodic screening surveys should be revised.

As discussed in Comment 3.1.7, proposed repair or corrective action requirements for alternative technology should not disincentivize their use. API supports that a full site follow-up OGI survey fulfills the annual OGI survey requirement (where applicable) as indicated in §60.5398b(b)(3)(iii). Regarding the proposed requirements for periodic screening in §60.5398b(b)(4), API offers the following suggestions:

- **The requirements on receiving results of periodic screening and conducting follow-up surveys should be separated from other repair requirements to avoid confusion.** The language in §60.5398b(b)(4) implies that receiving periodic screening results and conducting follow-up surveys are repair requirements when they are both monitoring requirements to detect or confirm leaks.
- **The timeline for receiving results of periodic screening should be extended from 5 calendar days to 5 business days.** Periodic screening surveys can cover hundreds of sites, and so vendors and operators need additional time to process the data for further action.
- **Follow-up surveys and inspections should be limited to sites where the source of emissions cannot be identified based on the localization performance of periodic screening results and other operational information.** Follow-up OGI surveys and cover and closed vent system inspections should not be required if the source of detected emissions can be identified based on the localization performance of the

alternative technology and/or other data. Alternative technology has varying degrees of localization performance in terms of being able to identify emissions on the site-level, equipment group-level, equipment-level, or component-level. Our proposed follow-up action process gives operators the necessary flexibility in responding to detected emissions and is presented in Figure 2and described in detail below.

Figure 2. Flowchart of Proposed Follow-up Actions for Periodic Screening Surveys



When emissions are detected in a periodic screening survey, the operator first tries to identify the source of emissions from the survey results and other available information. For safety and cost reasons, follow-up surveys in the field should be limited to situations where additional information is needed to identify or confirm the source of detected emissions. If the source of detected emissions can be identified, next steps would be based on the type of source.

- If the source of emissions is permitted or otherwise authorized, including maintenance activities, no further action would be required other than to keep documentation. Examples include, but are not limited to, engine or turbine exhaust, uncontrolled storage vessel, planned compressor blowdown, planned engine or turbine startup or shutdown, or properly operating control device. This situation is especially important to compressor stations where periodic surveys are likely to detect emissions from sources operating in compliance with applicable requirements.
- If the source of emissions is a process upset, leak, or other unauthorized release, the operator should be able to directly take necessary corrective actions rather than spending time and effort on a follow-up survey to confirm the source. Taking direct action with the appropriate timelines reduces emissions faster than conducting a follow-up survey first. If the operator determines that a follow-up survey is appropriate to confirm the source of detected emissions, they should be

able to conduct one based on the localization performance of the technology or an optional full site survey.

If the source of detected emissions cannot be identified, operators would conduct a follow-up survey limited to the localization performance of the alternative technology or conduct a full site survey to satisfy the annual OGI survey requirement (if applicable). If two or more full site surveys are conducted within a 12-month period, the most recent full site survey would determine the deadline for the next required annual OGI survey (if applicable). As an example, an alternative technology that can only detect leaks on the site level would require a full site survey while one that can detect leaks down to the equipment would require follow-up surveys only on equipment with detected leaks. Requiring a full site survey anytime that emissions are detected from periodic screening surveys is practically the same monitoring requirement as the primary AVO/OGI requirements but with the additional cost of conducting periodic screening surveys. Due to the large volume of data that can be generated from periodic screening surveys, limited follow-up surveys allow OGI resources to be used in a focused and cost-effective manner. Limited follow-up surveys could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to a full follow-up survey required for every time emissions are detected during a periodic screening survey.

- **Repair timelines should be consistent with AVO/OGI requirements.** Repair timelines should be consistent between traditional and alternative leak detection programs to streamline compliance and facilitate the use of multiple technologies. Therefore, the language in §60.5398b(b)(4)(iii) should simply reference the appropriate repair requirements for fugitive emissions components and covers and closed vent systems.
- **The proposed investigative analysis for control devices in §60.5398b(b)(4)(iv) and covers and closed vent systems in §60.5398b(b)(5) should be initiated within 5 business days.** While API recognizes the importance of proper control device and cover and closed vent system operation, we propose that the investigative analysis be initiated within 5 business days of either receiving the periodic screening survey results in the case that the control device, cover, or closed vent system can be identified as the source of emissions or conducting the limited or full site follow-up survey, whichever is later. This proposed timeline would be consistent with the framework we propose for the SERP in Comment 1.1. EPA's proposed 24-hour timeline is too short to be practical.
- **The proposed investigative analysis for covers and closed vent systems in §60.5398b(b)(5) is more stringent than the repair requirements under §60.5416b(b)(4) and should be removed.** As proposed in §60.5398b(b)(5), a leak or defect in a cover or closed vent system detected by follow-up inspections would require additional analysis beyond repair, including a determination of whether it was operated outside of its design. A leak or defect in a cover or closed vent system detected by routine inspections would be subject only to repair under §60.5416b(b)(4). The investigative analysis for covers and closed vent systems under the alternative technology requirements goes beyond the primary standards, and so §60.5398b(b)(5) should be removed.
- "**Root cause analysis" should be replaced with "investigative analysis".** Consistent with Comment 3.2, the term "investigative analysis" should replace "root cause analysis" in §60.5398b(b)(4)(iv) and §60.5398b(b)(5) (if that requirement remains).

3.4 Comments Specific to Continuous Monitoring Technology

We support EPA's inclusion of continuous monitoring in §60.5398b(c), and our members believe there is great potential in the use of continuous / near-continuous methane monitoring technologies. However, some of the proposed elements are problematic for practical implementation and use of continuous monitors. Therefore, we offer the following comments to craft a more functional continuous monitoring program based on the types of monitors that currently exist, focused on the desired outcome of detecting methane emissions at oil and natural gas production facilities to identify necessary response or repairs, if warranted.

3.4.1 The use of continuous monitoring technology within the periodic screening matrices must be clarified.

The proposed rule language is unclear whether continuous monitoring technology could also be used under the periodic screening survey requirements in §60.5398b(b) and associated matrices. For continuous monitoring technology that simply detects rather than quantifies methane emissions, these technologies could be used for periodic screening surveys. In these situations, the continuous monitor acts like a smoke alarm to notify operators of potential issues. Since continuous monitors can be used more frequently than monthly, EPA should consider adding a more frequent tier or a separate continuous monitoring row to the matrices. The equivalent emission reductions from continuous monitoring could be demonstrated through appropriate modeling. **We recommend incorporating continuous monitoring into the alternative screening matrix for the reasons discussed and to streamline inclusion into the monitoring plan framework we have described in Comment 3.1.6.**

3.4.2 The framework for continuous monitoring should be designed with both fenceline and within-the-fenceline technologies in mind.

As written, EPA's proposed requirements for continuous monitoring appear to be designed for fenceline technology. EPA should clarify that both fenceline and within-the-fenceline technologies can be used and provide details on how implementation would differ between them. API fully expects continuous monitoring technology for methane detection to come within the fenceline and get closer and closer to the source, unlocking emissions reduction potential that is unlikely to be realized by sensors installed on the perimeter. These within-the fenceline technologies will not have many of the limitations of today's fenceline solutions – including no need for wind or meteorological data because these sensors will be in closer proximity to equipment. Limiting the continuous monitoring requirements in this rulemaking to fenceline only would potentially reduce incentives to develop more advanced technology.

3.4.3 Currently available continuous / near-continuous monitoring technology detect methane emissions. The requirement for quantification should be amended.

Current continuous or near-continuous monitors are used to detect emissions and allow for a real-time response by operators; however, these monitors are not and should not be treated as a continuous emission monitoring system like a more traditional "CEMS". These monitors are "high frequency" monitors and not necessarily "continuous" in a traditional sense. The main focus of the monitors should be in the detection of emissions similar to the current OGI framework where the technology is used to find a leak and an operator can then respond, and if appropriate, to fix the leak.

The proposed framework should not be limited by a technology's ability to quantify emissions as this severely limits the types of monitors that can be used and offers a disincentive for operators to deploy the high frequency monitors currently available for deployment. Many technologies on the market today purport to quantify, but industry experience is that the value and accuracy is driven by the system's ability to act as a smoke alarm, where a certain threshold triggers a response system that notifies operators. There is no continuous monitoring technology today that actually "measures" a rate. The "quantification" capability is not derived from the underlying "smoke alarm" sensor but layering that sensor with wind, meteorological and other plume model / inversion model information / assumptions, which has untenable uncertainty.

Therefore, we believe these types of monitors should be considered as effective as the BSER standard, which is quarterly OGI for many larger well sites, central production facilities, and compressor stations. This proposal would have the technologies follow an approach similar to the matrix for other alternate technologies provided in §60.5398b(b) and Tables 1 and 2 to Subpart OOOOb and not follow the action levels in §60.5398b(c).

3.4.4 Continuous / near-continuous monitors should be evaluated against BSER, which is quarterly OGI.

As mentioned, currently available monitors allow for an alarm and response framework that allows operators the ability to evaluate the alarm and mitigate potential leaks. Due to this, continuous monitoring should be compared against the effectiveness of the technology in allowing response and potential repair of leaks against the BSER requirement of quarterly OGI and not based on the type of "fenceline" type framework that has been proposed. Per §60.5398b(c)(1), EPA has defined continuous monitoring as **"***the ability of a measurement system to determine and record a valid methane mass emissions rate of affected facilities at least once for every twelve-hour block."* This equates to daily scans at the facility, which sets an unrealistically high bar for implementation when compared against BSER that sets the most stringent monitoring at quarterly OGI and monthly AVO. The use of high frequency monitors should be consistent with BSER based on the detection capabilities of the monitors.

3.4.5 If EPA keeps its proposed framework for continuous monitoring, the proposed action levels should be revised.

While API overall recommends that continuous monitoring be incorporated with periodic screening to create a single framework for alternative technology, we have concerns with the proposed action levels if EPA choose to keep its proposed separate framework for continuous monitoring. The proposed action levels are based on EPA's FEAST modeling, which does not accurately characterize the effectiveness of AVO and OGI as discussed in Comment 3.1.4. We see merit in including a framework for future technologies that could detect and more accurately quantify emissions, but the currently proposed thresholds are not reflective of actual operations.

Regarding the proposed action levels in §60.5398b(c)(4), API offers the following suggestions:

- **Action levels should be based on detected emissions above an established baseline.** As proposed, the action levels appear to be based on total site emissions, which includes routine or baseline emissions, rather than emissions above an established baseline. Under continuous monitoring, fugitive emissions from leaks are additive to baseline emissions, but they are not additive under AVO/OGI/Method 21 and periodic screening programs. Action levels based on total site emissions effectively sets a limit on site emissions without considering the size or number of emission sources at a site, which could disincentivize the use of continuous monitoring, especially at larger sites. Also, failure to consider baseline emissions

would not exclude contributions from other nearby sources of methane emissions including but not limited to other sites, farming activities, graywater trucks, human populations, etc. EPA should revise the action levels to be based on emissions above baseline and propose how operators establish those baseline emissions.

- **The rolling 90-day (long-term) action levels should be removed as they have no equivalent in the AVO/OGI/Method 21 or periodic screening requirements.** Both the AVO/OGI/Method 21 and periodic screening programs require action to address emissions detected during the monitoring; in other words, emissions are compared to an established immediate or short-term threshold. Neither program has a long-term emissions threshold for action like the rolling 90-day action levels proposed for continuous monitoring. A long-term action level is at best a lagging indicator of an event and would make the investigative analysis of an exceedance more challenging. EPA has not clarified how operators should treat exceedances of the short-term action level that could also cause an exceedance of the long-term action level; operators resolve the short-term event in a timely fashion but may still exceed the long-term action level without any additional events or leaks. Based on these various reasons, EPA should either incorporate continuous monitoring completely into the screening matrix or remove the long-term action levels from the separate continuous monitoring framework.

- **The rolling 7-day (short-term) and rolling 90-day (if they remain) action levels should be revised.** The proposed action levels are too low and therefore practically disincentivize the use of continuous monitors. Despite being the most frequent detection method (every 12 hours as proposed), the proposed short-term action levels of 15 or 21 kg/hr are both below 30 kg/hr, which is the detection threshold for the most frequent periodic screening technology (monthly). A typical minimum threshold for actionable detection and notification is 20 kg/hr for today's technology. The lower the action level, the higher uncertainty on which source is causing the detection, and the likelihood for monitors to detect permitted or other background emissions. One potential solution is to have the short-term action level based on a fixed level to address smaller sites (e.g., wellhead only sites) or a variable level from baseline emissions (e.g., 200% of baseline emissions) to address larger sites.

  The long-term 1.2 or 1.6 kg/hr action levels may also be below the baseline emissions for many sites, which would be especially problematic if they represent total site emissions. Some operators, therefore, would effectively be unable to adopt continuous monitoring for NSPS OOOOb or EG OOOOc compliance.

3.4.6 We support timely and flexible follow-up actions to address any leaks found and request similar repair timeframes consistent with §60.5397b and §60.5416.

API supports the flexible language proposed in §60.5398b(c)(6) that describes initiating an investigative analysis to determine the primary reason for the emissions detected. We believe an operator can perform this investigation in numerous ways including using site-specific data. Due to the various ways that continuous monitors may be used for emissions detection, different follow-up actions may be appropriate for this technology when compared to AVO, OGI, or Method 21. While we appreciate the flexibility, we offer the following suggestions so that follow-up actions do not disincentivize the use of continuous monitoring as discussed more generally in Comment 3.1.7:

- **The timeline for initiating the investigative analysis should be extended from 5 calendar days to 5 business days.** Similar to periodic screening, additional time is needed for data validation.

- **EPA should clarify that the investigative analysis and corrective actions can be conducted remotely where feasible.** Operators should be able to conduct an initial evaluation of detected emissions based on SCADA or other operational data rather than sending a person to the site. Due to safety and cost concerns, operators typically limit the amount of time in the field. Remote investigative analysis and corrective actions could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to an onsite analysis required for each instance of detected emissions.

- **EPA should also clarify that limited or full site follow-up OGI surveys should be allowed in response to emissions detected by continuous monitoring depending on the localization performance of the continuous monitor(s)**. A limited or full site follow-up OGI survey may be a useful tool in identifying the source of emissions and therefore appropriate corrective actions. API recommends that the proposed follow-up action process for periodic screening surveys based on localization performance also apply to continuous / near continuous monitoring; refer to Comment 3.3.2 and Figure 2 for more details.

- **The timeline for completing the investigative analysis and initial corrective actions should be 30 days, not 5 days as proposed.** Follow-up actions for continuous monitoring should be consistent with repair timelines for OGI inspections.

- **Consistent with our suggestions in Comment 3.2, we suggest all references to “root cause analysis” be amended to “investigative analysis”.**

4.0 Associated Gas Venting from Oil Wells

API recognizes the environmental benefit of eliminating the venting of associated gas from oil wells that do not currently recover gas to a sales line, for injection, or for onsite fuel as its primary use. We disagree with EPA’s approach to the control standards proposed including the level of recordkeeping and reporting as it far exceeds the normal level of compliance assurance typically expected from an NSPS. An initial analysis[25] of the impact of the rule on potential production indicates that if the final rule were to eliminate flaring of associated gas, or is implemented in such a way that the practical effect is to eliminate flaring of associated gas, it could result in a substantial loss to production. Such a restriction or implementation would not be supported by API. Should the final rule either expressly or practically eliminate flaring of associated gas, it could be technically infeasible and not cost effective.

We offer the following suggestions with the belief that it is possible to create a manageable regulatory framework that targets the emissions from associated gas at areas without gas gathering infrastructure, including practical compliance assurance, recordkeeping, and reporting.

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[25] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API's request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

4.1 We support recovering gas to sales, for reinjection, used as onsite fuel, or routing gas to a control device. We do not support the additional certifications against emerging technologies prior to flaring associated gas.

We continue to support how EPA had described the proposed requirements for associated gas from oil wells in their November 2021 preamble description, but we do not support the hierarchy of the compliance options and associated recordkeeping and reporting requirements as proposed and believe the requirements should be technology neutral. Specifically, we support:

- Recovering gas to sales in §60.5377b(a)(1) (see also Comment 4.2).
- The beneficial use of the associated as onsite fuel proposed in §60.5377b(a)(2).
- Reinjection of the recovered gas into the well or injection of the recovered gas into another well for enhanced oil recovery proposed in §60.5377b(a)(4).
- Flaring the gas such that 95% control efficiency is achieved as proposed in §60.5377b(b).
- An annual reporting requirement focused on periods of venting.

We do not support the requirement to make an infeasibility demonstration and safety and technical certification statements in order to use a flare to reduce these emissions[26]; especially at oil wells that are connected to gas gathering infrastructure and only temporarily flare gas when unable to sell the gas (see also Comment 4.2). We also note that EPA even uses controlling associated gas with a control device such as a flare as justification for the storage vessel requirements (87 FR 74793) *"…these sites also may be subject to standards for oil well with associated gas and the compliance burden is shared between those affected facilities to ensure emissions from both storage vessels and oil wells with associated gas are reduced by 95 percent."* This statement is evidence of EPA's clear expectations of the use of flares at oil well facilities that may have associated gas, making the need for these additional demonstrations arbitrary.

While we support the concept of other types of beneficial use proposed in §60.5377b(a)(3), we do not support the list of options proposed in §60.5377b(b)(1) (methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas). Each option listed requires specialized equipment, capital investment, and additional energy to implement the technology that would generate emissions, some of which may be greater than flaring the associated gas directly. Furthermore, the cost-benefit of the proposed hierarchy of requirements has not been adequately justified by the EPA. In fact, EPA has not considered the technical feasibility, costs, or benefits from any of these options in the updated Technical Support Document[27].

4.2 The provisions for associated gas at oil wells that primarily recover associated gas to sales, for injection, or used for onsite fuel must be adequately delineated from associated gas from oil wells that do not have adequate or accessible gas gathering infrastructure.

Specifically, the notion that *"recovering associated gas from the separator and routing the recovered gas into a gas gathering flow line or collection system to a sales line"* constitutes a control option as proposed under

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[26] If retained, the infeasibility demonstration that is a prerequisite to control of associated gas must include consideration of commercial availability of alternatives to pipeline injection and of site economics. Consider, for example, the World Bank's "Zero Routine Flaring by 2030," which seeks "to implement economically viable solutions to eliminate [routine] flaring [of associated gas] as soon as possible."

[27] Supplemental TSD Chapter 6 Associated Gas October 2022 / EPA-HQ-OAR-2021-0317-1578_attachment_7.xlsx

§60.5377b(a)(1) is exceptionally problematic since this explains standard business operations for thousands of wells producing a vital energy resource throughout the country. Including this option within the proposal creates tremendous administrative burden in maintaining the records proposed in §60.5420b(c), without generating environmental benefit as the gas is typically being captured to a sales line already. Selling natural gas is part of our business and this sets a uniquely unjustifiable precedent since operators are in the business to sell as much of the produced gas as possible. In the preamble (87 FR 74779), EPA states *"In addition…a significant addition to the proposed rule is the establishment of requirements for situations when associated gas from an oil well that is primarily either routed to a sales line or used for another beneficial purpose is unable to utilize the gas in that manner due to gathering system or other disruptions."* We agree that these wells should have special requirements for the sporadic, short periods of time that gas cannot be recovered, but the current provisions proposed in §60.5377b(a) do not adequately address associated gas that is typically recovered.

For wells where associated gas from the separator is designed and configured to be recovered, we support simplification of the requirements that focus on the short periods of time when gas is not recovered for sale, injection, or reuse. Specifically, we support flaring the gas by using a permanent or temporary control device[28] that achieves 95% efficiency during periods of time when the associated gas is routed to the control device. In this scenario when a well that is configured to route gas to sales or for reinjection can no longer recover the gas for its primary use, the gas should be immediately routed to the flare as soon as practicable. Since EPA has already acknowledged in the preamble (87 FR 74780) that these situations do occur and are outside the control of the well operator, we do not support making technical or safety demonstrations where disruptions or interruptions in the gas gathering infrastructure result in the need to route the associated gas to a control device for temporary periods. For wells that primarily recover gas for reinjection, conducting compressor maintenance may necessitate temporary periods of flaring. This is reasonable given that a facility is designed with a certain configuration for handling the disposition of associated gas and it is unreasonable to expect facilities to design for multiple uses based on emerging technologies before they can resort to flaring; especially during these short intermittent periods.

Any retention of technical demonstrations, for wells that do not primarily recover associated gas, should include economic viability.

4.3 EPA should include a definition for associated gas.

EPA did not include a defintion of associated gas within §60.5430b or §60.5430c, which we do not believe was EPA's intent. Within the preamble[29] EPA uses the following language when describing associated gas. We believe this language with a few additional clarifications would be appropriate to clearly describe associated gas from oil wells for the purposes of NSPS OOOOb and EG OOOOc. The distinctions we provide explicitly determine which separator the requirements proposed in §60.5377b(a) would apply, providing clear transparency for the regulated community.[30]

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[28] A temporary control may be needed in certain situations that an operator may not have planned for or may not have expected. . Allowing both permanent or temporary flare provides flexibility for locations where an existing permanent control device cannot be used or where has not yet been installed.

[29] 87 FR 74778

[30] Without a clear definition, there is uncertainty of what gas EPA seeks to control. For example, some members debate if EPA meant to include flaring from storage vessels. By limiting to the first stage of separation, operators will clearly know what associated gas is applicable.

> *Associated gas means the natural gas which originates at oil wells operated primarily for oil production and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon during the initial stage of separation after the wellhead.*

4.4 Using associated gas as purge or pilot gas for a control device should be considered beneficial use.

Pilot and/or purge gas allow flares and other control devices to operate safely and effectively to reduce emissions. Furthermore, NSPS OOOOb and EG OOOOc require flares and enclosed combustion devices to have a continuously burning pilot flame when the flare is in use. Enclosed combustion devices are also required to maintain a minimum inlet flow rate, which may require supplemental fuel. In other words, pilot and purge gas are part of the fuel requirements for a flare or enclosed combustion device and are not controlled vent streams.

Since the use of associated gas as an onsite fuel source is one of the proposed beneficial use options in §60.5377b(a)(2), we request that EPA clarify that purge or pilot gas for a control device is considered part of onsite fuel use as shown in the following suggested edit to §60.5377b(a)(2):

> *Recover the associated gas from the separator and use the recovered gas as an onsite fuel source, which may include using the recovered associated gas as purge or pilot gas for a control device or flare.*

As an alternative, EPA could clarify that purge or pilot gas for a control device is considered a useful purpose option under §60.5377b(a)(3).

4.5 Special considerations for handling associated gas from wildcat and delineation wells

In our January 31, 2022 comment letter, we asked EPA to allow certain provisions for wildcat or delineation wells in its proposal with respect to the associated gas from oil well provisions. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. In many instances an operator will not know or understand the composition of the gas until after the well is drilled. EPA has acknowledged this fact within the definitions that have been published in §60.5430a and maintained in the proposed §60.5430b & §60.5430c where the terms are defined as:

> *Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.*
>
> *Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.*

In response to our January 31, 2022 comment letter, EPA stated (see 87 FR 74780):

> *"The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for these situations due to lack of specific sufficient information. Therefore, the EPA is interested in additional information on gas compositions of associated gas that would make it both unusable for a beneficial purpose and unable to be flared. The EPA is not only interested in why commenters feel these situations warrant an exemption from the associated gas standards as proposed, but also*

> *what methods are currently in use, or could be used, to minimize methane and VOC emissions in these situations."*

Like provisions within NSPS OOOOa for well completions, EPA should allow special considerations for handling associated gas since these activities are exploratory in nature and are typically not located near existing infrastructure. Wildcat or delineation wells will typically only produce for short period of time after flowback ends in order to complete well testing where the production flow rate is determined along with other parameters such as the gas composition before the well is shut-in or capped, which is regulated based on state protocols.[31] These wells are typically located in remote locations far from any form of permanent infrastructure thereby disallowing any beneficial reuse from a practical and logistical standpoint since the gas composition is not known.

As an example, on the Alaskan North Slope, ice roads must be built to access locations where exploration activities are taking place because roads do not exist, and there is not access/connection to existing oil and gas infrastructure. As we described above, characteristics of associated gas from these wildcat / delineation wells is unknown and therefore it is not wise to use as an onsite fuel source. Currently under NSPS OOOOa and under proposed NSPS OOOOb, the initial well flowback is subject to the well completion operation requirements, which allow for use of a completion combustion device. After the flowback ends, the well undergoes cleanout and a well test (extended flowback) is conducted to determine reservoir characteristics. There will still be open top tanks and a combustion device present; however, this equipment will only be utilized for a very short duration. The compliance requirements for both the provisions in §60.5377b(a) or §60.5412b do not allow for realistic implementation for such unique and short-term operations which are not permanently producing oil from a well.

Since wildcat or delineation wells will typically cease production in well under 180 days[32], a temporary or portable combustion device similar to those used to control emissions from well completions is appropriate to reduce VOC and methane emissions. We therefore request EPA allow any associated gas produced from wildcat or delineation oil wells be routed to a completion combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways). Due to the temporary nature of these activities, the control device compliance requirements should mimic the requirements of control devices utilized for well completions affected facilities, i.e., operated with a reliable continuous pilot flame and no further compliance requirements.

Suggested Redline for inclusion within §60.5377b:

> *For each wildcat or delineation oil well with associated gas at a well affected facility, capture and direct recovered associated gas from the separator to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

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[31] EPA determined well testing "*conducted immediately after well completion, is considered part of the well completion"* for the purposes of reporting emissions under the Greenhouse Gas Reporting Program (see definition of Well Testing Venting and Flaring in §98.238).

[32] We note the initial performance test for enclosed combustion devices not tested by a manufacturer would not be required until within 180 days after initial startup or start of production. Wildcat or delineation wells typically do not produce for this long to warrant compliance with these provisions. Furthermore, duration of well testing flowbacks from wildcat and delineation wells can be limited to 30 days per other agency regulations/guidance, e.g. BLM's NTL-4A guidance (and proposed Waste Prevention rule) generally limits this activity to 30 days, extension beyond 30 days requires additional approval by the agency.

4.6 EPA’s Model Plant Analysis Assumptions

Based on preliminary review of EPA’s technical support document that was issued in conjunction of the Supplemental Proposal, the associated gas model plant analysis does not include assumptions reflective of actual proposed requirements.

- In our January 31, 2022 letter, we stated *“a more representative cost for installing a flare suitable to control associated gas would be $100,579, based on the average costs EPA uses for analyzing storage vessel controls.”*[33]. We also stated, *“that we did not include the costs from EPA’s Workbook ‘MP1 Plus Monitors.xlsx’ as this would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the proposal. If EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA’s cost analysis.”* In the Supplemental Proposal EPA has proposed additional parametric monitoring but has not included these costs in the analysis.

- The EPA should consider model facilities that have existing control devices but now need to install the correct flow and other parametric monitoring equipment as this would be a type of model plant scenario not evaluated by the EPA.

- None of the beneficial reuse emerging technologies have been included within the model plant analysis. It is unclear how EPA has justified the inclusion of these technologies related to costs, feasibility or environmental benefit/disbenefit.

- EPA includes no costs associated with the technical demonstrations proposed. There are direct costs associated with the engineering certification process, whether companies support in-house engineers or leverage third parties. In previous API comments we have provided to the EPA, we estimated certifications to be $2,000 - $9,000.[34]

- The EPA seems to bias the data selected for baseline emissions to fit their expectation and not based on actual reported data. In section 6.3.1 of the technical support document[35] EPA states,

  > *There were 95 facilities/basins that reported associated gas venting emissions [through GHGRP subpart W data]. For each facility/basin, the number of wells venting is reported, along with the total methane vented from all wells. For each facility/basin, we calculated the average emissions per well. These average well emissions ranged from 0.015 tpy to over 2,400 tpy. Almost 20 percent of the facilities/basins had average well methane emissions less than 0.2 tons per year. Explanations of the specific causes of emissions is not provided in the GHGRP subpart W outputs, but it would be expected that routine venting of associated gas would result in emissions greater than this level. In order to avoid selecting a well associated gas venting level that was unreasonably low, a weighted average well emissions level was calculated, using the total emissions from the facility/basin as the weighting factor. The result is an estimated average*

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[33] EPA-HQ-OAR-2021-0317-0039
[34] EPA-HQ-OAR-2017-0801
[35] EPA-HQ-OAR-2021-0317-1578

> *annual methane emissions level of 344 tpy. Applying the representative composition yields a representative VOC emissions level of 96 tpy.*

Within these statements, EPA acknowledges that there are very low methane emissions generated from wells that only temporary flare associated gas when the primary recovery method is not available (i.e. routing to sale, for injection, or used as onsite fuel). However, the EPA in this proposal has not made the distinction between facilities that temporarily flare versus those that are truly stranded.

5.0 Control Devices, Covers and Closed Vent Systems

API supports EPA's decision to maintain the 95% control efficiency standard for control devices within NSPS OOOOb and EG OOOOc, and we acknowledge EPA's desire to assure proper control device performance. The following recommendations will allow this goal to be achieved more effectively at well sites, centralized production facilities, compressor stations, and natural gas processing plants. Specifically, the proposed control device and cover and closed vent system requirements present technical feasibility, timing, and cost issues. To address these concerns, NSPS OOOOb and EG OOOOc should allow for more cost-effective monitoring alternatives and better alignment between monitoring requirements for manufacturer-tested enclosed combustion devices and other enclosed combustion devices. Comments concerning both control devices and closed vent systems are presented in this section.

5.1 Emissions detected from covers and closed vents system do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

EPA states in the Preamble that when a leak is detected in a cover or a closed vent system during a fugitive emissions survey, alternative screening survey, or by a continuous monitoring system, "*the emissions would be considered a violation of the [no identifiable emissions] standard and thus a deviation*"[36]. The "no identifiable emissions standard" or NIE standard is a design and work practice standard (***emphasis added***).

> *You must **design and operate** the closed vent system with no identifiable emissions as demonstrated by §60.5416b(a) or (b), as applicable.37*

As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. EPA has presented no reason in the Proposal to depart from its historical approach regarding fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in

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[36] 87 FR 74804

[37] §60.5411b(a)(3)

compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed.

A “no identifiable emissions” or “no detectable emissions” standard cannot constitute a numerical emissions limitation since BSER must be achievable, so the standard must be applied as a work-practice standard. Even the most well-designed and operated system will develop a leak due to wear and tear on equipment. A zero emissions standard for cover and closed vent system components is practically unachievable because some leaks will happen in the normal course of operations (e.g., typical fugitive leaks) and some develop due to causes beyond an operator’s control. Consider that if a leak from a rusty bolt on a pipe flange is only subject to the standard LDAR work practice standard, then a leak from a rusty bolt on a cover or closed vent system should also only be subject to the standard work practice standard. There is no reason why a typical fugitive leak should be treated differently simply because it occurs on a cover or closed vent system.

Additionally, a leak may develop due to malfunctions or a foreign object (e.g., sand or dust), both of which are not reasonably within the control of the operator. Such leaks are not caused by inadequate design or improper operation and cannot constitute a violation of the “no identifiable emissions” standard. API recognizes the possibility of improperly operating a cover or closed vent system (e.g., forgetting to close a thief hatch), but EPA should clearly differentiate these types of leaks from those described above. For these reasons, EPA’s application of the standard as a numerical emission limitation is not only unachievable but will also have will have a chilling effect on companies that aim to do voluntary leak surveillance, and disincentivize the use of more sensitive instruments. EPA should encourage and incentivize operators to conduct additional voluntary monitoring without the fear of an automatic violation if a leak is detected from a cover or closed vent system.

Lastly, CAA § 111(h)(2) provides that a work practice standard should be prescribed in lieu of a standard of performance (i.e., numeric emissions limitation) when “a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant.” That is precisely the case with EPA’s proposed NIE standards. The NIE standards do not apply to emissions from the storage vessel or equipment to which the closed vent system is installed. Rather, the proposed NIE standard applies to the closed vent system itself. In this case, it is obvious that there is no “conveyance” through which the regulated pollutants would be emitted or captured. To accomplish such an outcome, the closed vent system to which the NIE standard applies would have to be enclosed within another closed vent system or similar permanent total enclosure in order for the regulated emissions to be captured for subsequent control or venting. Requiring such a system would be inordinately costly, highly impracticable, and likely impossible. This is precisely why LDAR standards have been expressed from the inception of such programs almost exclusively as work practice standards. In short, the NIE standard cannot be effectively construed as a zero-emissions standard, as EPA proposes, because no “conveyance” exists that allows for capture of the regulated emissions and application of such a standard to an emissions point.

5.2 Supply chain delays for acquiring flow meters or other monitoring equipment necessitates the initial compliance period must be extended to at least one (1) year after publication in the Federal Register.

Due to EPA’s proposed designation of the applicability date aligned to the November 2021 proposal (see Comment 12.1), operators may not have the adequate flow and net heating value monitoring technology in place for all sites subject to the provisions proposed in NSPS OOOOb, because these additional monitoring requirements were only contemplated but not specifically proposed in that initial proposal. Since EPA’s proposal for consistent control device monitoring requirements regardless of the affected facility will apply to both NSPS

OOOOb and EG OOOOc, the number of control devices subject to monitoring requirements will increase significantly. The current supply chain delay for acquiring flow meters or similar monitoring equipment is currently approximately 6 to 8 months. This delay within the supply chain is expected to be exacerbated based on both NSPS OOOOb and EG OOOOc implementation over the coming years.

In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk.Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap.

As an alternative, a site shutdown to install control device monitoring equipment will result in emissions from the shutdown and purging of equipment and piping. Shutdowns at midstream compressor stations or gas plants could result in gas venting, gas flaring, or a shut-in at upstream facilities. A shorter compliance period will multiply these disruptions as operators work to comply with NSPS OOOOb.

In the 2012 NSPS rule[38], EPA allowed implementation for storage vessel requirements to be phased-in to accommodate the vast number of affected facilities and the number of control devices that would be needed to be acquired. Other state rules, such as those in Colorado and New Mexico[39], have allowed for an orderly phase-in period for certain requirements. EPA must consider that a similar compliance schedule is warranted in the proposed NSPS OOOOb and EG OOOOc based on similar constraints and concerns for acquiring the appropriate monitoring equipment that has historically been exempt from control devices for storage vessel affected facilities. The current supply chain delays in acquiring equipment and limited resources to install equipment are expected to be exacerbated by the large number of control devices subject to monitoring under NSPS OOOOb or EG OOOOc.

Based on feedback from members, we request the initial compliance period for control device flow and net heating value monitoring requirements be extended from 60 days after final publication in the Federal Register to at least 1 year after publication in the Federal Register to allow operators time to order and install the necessary meters assuming that the applicability is based on the December 6, 2022 and other our comments concerning reconstruction and modification are addressed. Additional time, at least another year, would be required if the rules are finalized as proposed. Specifically, compliance with the flow and net heating value monitoring requirements at §60.5417b(d)(1)(vii)(A), §60.5417b(d)(1)(viii)(B), and §60.5417b(d)(1)(viii)(D) along with related operational requirements must be extended to allow operators adequate time to procure and install the necessary monitoring equipment where appropriate as various new equipment is installed, or other equipment is modified or reconstructed.

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[38] See EPA's response at 77 FR 49525-49526.

[39] 20.2.50.122.B(3) NMAC and 20.2.50.123.B(1) NMAC

5.3 With the increased number of control devices subject to flow monitoring requirements, the accuracy requirement for flow meters should be ±10% of maximum expected flow.

For manufacturer-tested enclosed combustion devices, EPA is maintaining the current flow monitoring accuracy requirement of ±2% or better[40]. Historically, this requirement only applied to control devices for wet seal centrifugal compressors and was not required for control devices used to reduce emissions for other affected facilities under NSPS OOOO or NSPS OOOOa. Vent gases from centrifugal compressors have relatively stable flow rates while vent gas from storage vessels is intermittent, low pressure, low velocity / flow, and more difficult to measure.

Since EPA is proposing consistent control device monitoring requirements regardless of the affected facility controlled for both NSPS OOOOb and EG OOOOc, the number of control devices subject to flow monitoring requirements will increase significantly under NSPS OOOOb and EG OOOOc.

The ±2% accuracy requirement may not be technically feasible for most commercially available meters nor cost-effective for control devices on every affected facility at well sites, central production facilities, compressor stations, and natural gas processing plants. As mentioned in Comment 5.2, the availability and cost of meters are negatively affected by supply chain constraints and limited resources to install them. API has previously commented[41] on the challenges with flow monitoring at upstream facilities. This level of accuracy is also more stringent than the ±5% accuracy requirement for flare vent gas flow rates at velocities above 1 feet per second under Maximum Achievable Control technology (MACT) standards finalized under 40 CFR 63 SubpartCC (RMACT)[42].

Two types of commercially available flow meters that are commonly used are thermal dispersion meters or ultrasonic meters. Ultrasonic flow meters are the only identifiable meter that can achieve the ±2% accuracy, but this accuracy may decrease under low-flow or low-pressure conditions. While these meters are technically feasible to meet the proposed accuracy requirement, they may not be economically reasonable with an estimated cost of $20,000 to $30,000 each. In EPA's cost analysis for storage vessels controls[43], the cost of a flare with monitoring equipment was estimated but was not used in the subsequent BSER analysis for new or existing sites. Therefore, EPA did not fully consider the cost-effectiveness of the proposed monitoring requirements for control devices. Thermal dispersion flow meters are less expensive but may not meet the accuracy requirement with a typical accuracy of ±5% or better at high flows (accuracy decreases at pressures less than 25 psig). The lower pressure and variable flow rates from certain affected facilities such as storage vessels also make the accuracy requirement difficult to meet. If a control device is used for controlling atmospheric storage tanks only, it will be operating at less than 25 psig and so even a ±5% accuracy may be difficult to achieve; therefore, the flow meter accuracy requirement must consider this likely scenario. In colder conditions, like those experienced in North Dakota and other states, the liquid drop out caused by condensation can also reduce the accuracy of flow meters and make an accuracy of ±2% technically infeasible. Therefore, API proposes that the accuracy for control device inlet flow rate be increased to ±10% of maximum expected flow.

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[40] §60.5417(d)(1)(viii)(A) and §60.5417a(d)(1)(viii)(A)

[41] API's December 4, 2015, comments on the proposed Subpart OOOOa and January 31, 2022, comments on the proposed Subparts OOOOb and OOOOc.

[42] 40 CFR 63 Subpart CC Table 13

[43] EPA-HQ-OAR-2021-0317-0039, "StTanks_Control_Costs_v5.1.xlsx" and "EPA_Flares_Calc_Sheet_MP1plusmonitors.xlsx"

5.4 Flow monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices.

Manufacturer-tested enclosed combustion devices function similarly to other enclosed combustion devices with the only difference being the party responsible for stack testing; therefore, the proposed flow monitoring requirements should be consistent regardless of whether the device is tested by the manufacturer or owner/ operator. In comparing the proposed flow monitoring requirements for manufacturer-tested enclosed combustion devices at §60.5417b(d)(1)(vii)(A) and other enclosed combustion devices at §60.5417b(d)(1)(viii)(D), the following inconsistencies were noted and should be addressed.

- **No accuracy requirement is specified for other enclosed combustion devices.** As discussed above, the accuracy requirement for flow rate monitoring should be ±5% for both manufacturer-tested and other enclosed combustion devices.
- **Manufacturer-tested devices appear to be limited to flow meters while other enclosed combustion devices may use other parameter monitoring systems.** Other parameter monitoring systems combined with engineering calculations should also be an option for flow monitoring on manufacturer-tested devices especially considering the potential challenges in obtaining and installing a flow meter in a timely fashion. Other parameter monitoring systems are also needed in situations where flow monitoring is infeasible (e.g., low flow scenarios). These other parameter monitoring systems would be more stringent than MACT HH, which allows GRI-GLYCalc™ or other process simulation to calculate inlet flow rate for manufacturer-tested control devices[44].
- **Manufacturer-tested devices do not have an option to exempt the device from flow monitoring.** For enclosed combustion devices not tested by the manufacturer, maximum inlet flow rate monitoring is not required if a demonstration can be made using engineering calculations, and minimum inlet flow rate monitoring is not required if a backpressure valve is properly installed and operated. These alternative compliance options for flow rate monitoring should also be available to manufacturer-tested devices.
- **EPA should clarify that a backpressure preventer is a backpressure valve.** Since backpressure preventer is an unclear term, EPA should use the term “backpressure valve” instead.
- **Additional examples of other parameter monitoring systems should be added to the regulatory text.** To clarify and elaborate on the variety of other parameter monitoring systems that could be used in lieu of a flow meter, EPA should consider adding inlet pressure and line size as additional examples in the regulatory text.

Based on these items, API offers the following recommended redline of flow monitoring requirements for manufacturer-tested control devices in §60.5417b(d)(1)(vii)(A):

> *Except as noted in paragraphs (d)(1)(vii)(A)(1) through (4) of this section, ~~T~~the continuous parameter monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ~~±2~~ ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The flow rate at the inlet to the combustion device*

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[44] §63.773(d)(3)(i)(H)(*1*)

> *must be equal to or greater than the minimum flow rate and equal to or less than the maximum flow rate determined by the manufacturer.*
>
> (1) *If you can demonstrate, based on the maximum potential pressure of units manifolded to the control device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the control device cannot cause the maximum inlet flow rate determined by the manufacturer to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.*
>
> (2) *If you install and operate a backpressure valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.*
>
> (3) *Control devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*
>
> (4) *Pressure-assisted flares control devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

API also offers the following recommended redline of flow monitoring requirements for control devices not tested by the manufacturer in §60.5417b(d)(1)(viii)(D):

> *Except as noted in paragraphs (d)(1)(viii)(D)(1) through (4) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustor or flare. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement.*
>
> (1) *If you can demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustor cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section or the flare tip velocity limit in §60.18 to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.*
>
> (2) *If you install and operate a backpressure ~~preventer~~ valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.*
>
> (3) *Flares that are exempt from maximum inlet gas flow monitoring and enclosed combustion devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*
>
> (4) *Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

Given the small size, dispersed nature, and large number of units affected by this rule, these changes would appropriately reduce the burden of compliance while still providing for compliance demonstration and monitoring.

5.5 EPA must provide the minimum inlet flow rate for current manufacturer-tested control devices no later than publication of the final rule so that owners and operators are able to achieve compliance.

In the preamble[45], EPA states that previously tested manufacturer control devices "*would not need to perform new performance tests*" and "*[t]he zero-level at which the combustion control device was tested will be extracted from the previously submitted performance test report and added to the information on the EPA's website*". This minimum flow rate information must be added to the EPA's website[46] no later than publication of the final rule since owners and operators cannot extract the information themselves as the underlying test reports are not currently available on the website. This minimum flow rate information may also not be easily obtained from the manufacturer directly. EPA must provide this minimum flow rate information no later than publication of the final rule so that owners and operators are able to take any necessary action (e.g., purchase of a different control device or operational changes) to achieve compliance. If the minimum flow information is not provided by the publication of the final rule, EPA should consider implementing a longer initial compliance period (see Comment 5.2).

5.6 EPA should allow the use of alternative technologies within the proposed monitoring requirements.

Given the increasing number of control devices subject to proposed monitoring requirements, EPA should allow the use of alternative technologies to meet the monitoring requirements for visible emissions, continuous pilot flame, and minimum net heating value. Well sites, centralized production facilities, and compressors do not have the same utilities and instrumentation resources as refineries, so alternative technologies would provide more cost-effective monitoring of control device performance.

5.6.1 A smoking check should be the primary monitoring method for visible emissions from flares and enclosed combustion devices.

Thousands of flares and enclosed combustion devices will be subject to proposed monthly Method 22 observations and associated recordkeeping. Each of these observations requires 15 minutes and detailed records to document that the observation was conducted according to Method 22. In total, these observations will add up to hundreds to thousands of hours each month and thousands to tens of thousands of hours per year with no added environmental benefit if the device is operating properly. Compliance can more easily be monitored using a monthly smoking check with a record documenting the time of the observation and whether the control device is observed to be smoking. If the device is observed to be smoking, then operator would be able to either 1) assume the device failed the visible emissions requirement and immediately take corrective actions or 2) conduct the 15-minute Method 22 observation to determine whether the device meets the visible emissions requirement. A monthly smoking check could reduce the time required to monitor the device by more than 90%, and this saved

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[45] 87 FR 74796

[46] https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers

time could be used for other tasks with greater environmental benefit (e.g., conducting a required AVO and/or OGI survey while at the site).

5.6.2 Video camera systems should be allowed as an alternative to Method 22.

Since some sites are already equipped with video camera systems, EPA should also allow video cameras as an alternative method to conduct the required monthly smoking check or Method 22 visible emission observations for enclosed combustion devices and flares. Video camera systems are allowed as an alternative to Method 9 observation under Broadly Applicable Approved Alternative Test Method ALT-82[47]. Although these video camera systems have similar supply challenges to other monitoring equipment (see Comment 5.2), they should be an allowed monitoring alternative. To be consistent with the smoking check or Method 22 requirement, the camera would be used to remotely conduct a smoking check and/or 15-minute observation for visible emissions from the control device every month. Owners or operators would keep a record of this remote visible emission observation with similar information required for in-person smoking check or Method 22 observation. Artificial intelligence and machine learning should be allowed to continuously screen the video feed for smoke detection and if smoke is detected, alert the operator that a Method 22 follow-up is required. Making the requirements for video camera systems more stringent than the proposed monthly Method 22 observation would disincentive the use of this alternative. Recordkeeping and reporting of additional video records could pose potential security risks and data storage concerns.

5.6.3 An automatic ignition system with a flame monitoring device should be allowed as an alternative to a continuous pilot flame.

A continuous pilot flame requires propane or other supplemental fuel at sites without fuel gas. For sites with sour gas, a continuous pilot flame requires either using the sour gas as the pilot or bringing in propane or other supplemental fuel to supply the pilot. Burning propane or other supplemental fuel is costly and generates additional emissions when no vent streams are sent to the control device. Similarly, burning sour gas generates additional emissions including SO_2 and potentially uncombusted H_2S. Some state rules, such as New Mexico[48] and Texas[49], allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. Therefore, API proposes that an automatic ignition system with a flame monitoring device be allowed as an alternative to a continuous pilot flame.

5.6.4 The minimum net heating value demonstration should be simplified.

EPA should provide flexibility to operators by simplifying its proposed minimum net heating value demonstration alternative to continuous net heating value monitoring. Both the proposed continuous net heating value monitoring and demonstration alternative seem excessive considering that the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirements. These vent streams consist of mostly hydrocarbons, and the simplest hydrocarbon (methane) has a net heating value of approximately 900 Btu/scf, which is 450%, 300%, or 112% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf depending on the type of control device.

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[47] https://www.epa.gov/sites/default/files/2020-08/documents/alt082.pdf

[48] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(b) NMAC

[49] 30 TAC §106.492(1)(B)

The proposed minimum net heating value demonstration requires continuous monitoring over 10 days or a minimum of 200 hourly samples of inlet gas to the flare or enclosed combustion device. EPA's justification for such an extensive sampling campaign is *"to provide a large sampling set by which to assess the variability of the vent gas sent to the combustion device and to adequately characterize the tails of the distribution."*[50] EPA did not provide additional detail as to why it expects the distribution of vent gas composition to vary enough to potentially be below the required minimum net heating value. Such a large sampling set is unnecessary when the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirement.

Vent streams from oil well with associated gas, centrifugal compressor, and pneumatic controller in Alaska affected facilities are typically comparable to sales gas or natural gas. In AP-42, natural gas is listed as having a gross heating value of 1,020 Btu/scf (Section 1.4) or 1,050 Btu/scf (Appendix A). The "2011 Gas Composition Memorandum"[51] used in EPA's TSD also suggests net heating values well above the required minimum. Gas composition typically does not change unless certain actions occur at the site, such as adding a new well or refracturing an existing well. Even though the gas composition will typically change with new or modified well streams, composition remains well above the required minimum net heating value.

Vent streams from storage vessel affected facilities consist of more large hydrocarbons than sales gas and have a typical net heating value of 2,000 Btu/scf or more, which is 1,000%, 667%, or 250% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf, respectively. The addition of air from an open thief hatch could drop the heating value of tank vapors below the required minimum net heating value, but the proper operation of thief hatches and other openings are already addressed in the proposed cover requirements.

Vent streams from affected facilities that could potentially be below the minimum heating value requirement include compressors in acid gas service or those at Enhanced Oil Recovery (EOR) facilities. Both situations could have high carbon dioxide (CO_2) content which would lower the net heating value, so operators typically add assist gas or another vent stream with sufficient heating value to facilitate proper control device operation. In these limited situations, API proposes that flow monitoring of the assist gas and vent streams should be allowed as an alternative to the continuous monitoring of net heating value in these limited situations.

Since the vent streams from affected facilities are expected to have sufficient heating value, both the proposed continuous net heating value monitoring and demonstration alternative are economically unreasonable. Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000. These monitors may also experience operational issues with entrained liquids in the vent gas stream especially in colder climates and seasons. For the minimum net heating value demonstration alternative, the cost is expected to be $250,000 or more per demonstration. The cost of a vendor-conducted 10-day continuous monitoring campaign is estimated at a minimum of $250,000 to $275,000 while the cost of 200 hourly samples is estimated at a total of $300,000 to $400,000 with an average cost per sample of $1,500 to $2,000 including shipping and analysis.

Since EPA's proposed minimum net heating value demonstration is too onerous and costly, API proposes the following to provide operators the necessary flexibility to comply with net heating value requirements:

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[50] 87 FR 74795

[51] EPA-HQ-OAR-2010-0505-0084

- The 10-day demonstration be simplified to a single sample including the use of an appropriate, representative sample or an initial flare compliance assessment with §60.18 using Method 18 of Appendix A. If a representative sample is used, the operator must document why the sample is characteristic of the vent stream composition. If the sample or §60.18 assessment demonstrates that the net heating value is at least 150% of the applicable minimum value (i.e., net heating value of the sample is at least 300, 450, or 1,200 Btu/scf, as applicable), net heating value monitoring would not be required. After the initial demonstration, continuous compliance would be demonstrated through subsequent samples once every 3 years. If the initial or subsequent sample is below 150% of the applicable minimum net heating value, the operator would be required to conduct more extensive sampling as proposed below or install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- If an initial or subsequent sample does not meet 150% of the minimum net heating value, operators should have the option to conduct a more extensive sampling event with a lower threshold. API proposes that this more extensive demonstration consist of a minimum of 2 hourly samples or 2 hours of continuous monitoring per day for 7 days for a total of 14 samples. The same number of samples is required for a comparable net heating value demonstration under RMACT[52]. Net heating value monitoring would not be required if all 14 hourly averages or samples are above 120% of the applicable minimum net heating value requirement. After the initial 7-day demonstration, continuous compliance would be demonstrated through a grab sample taken once every 3 years. If the initial or subsequent samples are below 120% of the applicable minimum net heating value, the operator would be required to install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- As with the proposed flow monitoring requirements, net heating value monitoring or demonstration alternative should not be required if operators demonstrate that the net heating value is never expected to below the minimum required value using applicable engineering calculations including process simulation software. This alternative would be similar to MACT HH, which allows GRI-GLYCalc™ or other process simulation software to be used to estimate benzene or BTEX emissions from a glycol dehydration unit[53]. Continuous compliance would be demonstrated through a grab sample taken once every 3 years to verify that the minimum net heating value is being met.

5.7 Minimum operating temperature and associated monitoring requirements should be revised.

NSPS OOOOb proposes a minimum operating temperature of 760 °C and temperature monitoring for enclosed combustion devices that demonstrate that combustion temperature is an indicator of performance during initial performance testing. Other enclosed combustion devices (i.e., those for which combustion temperature is not demonstrated to be an indicator of performance) would be subject to net heating value monitoring requirements. Given the increased number of control devices subject to NSPS OOOOb and EG OOOOc, EPA should revise the minimum operating temperature and associated monitoring requirements in the following ways:

- **Allow operators the flexibility to comply with either temperature or net heating value requirements for enclosed combustion devices that demonstrate that combustion temperature is an indicator of**

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[52] §63.670(j)(6)

[53] §63.772(b)(2)(i)

performance. Some enclosed combustion devices, such as thermal oxidizers, are designed with a minimum operating temperature while others are not. Even if a device can demonstrate that temperature is an indicator of performance during testing, maintaining a minimum operating temperature during actual operation may be challenging and require additional supplemental fuel due to the low or intermittent flow of the vent streams. As proposed, a minimum operating temperature with associated monitoring is the only option for enclosed combustion devices that demonstrate combustion temperature is an indicator of performance. For those enclosed combustion devices, operators should be able to comply with net heating value requirements as an alternative.

- **Allow the minimum operating temperature to be established by performance testing.** Rather than a fixed minimum operating temperature, EPA should allow operators the flexibility to comply with a default minimum operating temperature of 760 °C or the value established by the most recent performance testing. The enclosed combustion device may be able to demonstrate compliance at an operating temperature below 760 °C. Also, additional supplemental fuel may be required to keep the device at a minimum operating temperature of 760 °C when it could achieve a 95% control efficiency at a lower temperature. Operators should be allowed to conduct performance testing as needed to establish a new minimum operating temperature.

- **Allow a minimum operating temperature and temperature monitoring for manufacturer-tested devices.** As proposed, the minimum operating temperature and associated monitoring applies only to enclosed combustion devices not tested by the manufacturer. Like operators, manufacturers should be allowed to demonstrate that combustion temperature is an indicator of performance through performance testing and allow temperature monitoring as an option for demonstrating compliance. Operation and monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices like our recommendation on flow monitoring in Comment 5.4.

5.8 Manufacturer-tested enclosed combustion devices should continue to be exempt from periodic performance testing.

Under NSPS OOOO and MACT HH, manufacturer-tested control devices are exempt from periodic performance testing. Under NSPS OOOOa, manufacturer-tested control devices on centrifugal compressors are exempt from periodic performance testing if the device has continuous flow monitoring. NSPS OOOOb proposes that manufacturer-tested control devices be subject to both periodic performance testing and continuous flow monitoring. These requirements appear contrary to both the technical challenges in conducting performance tests in the field reiterated by EPA and the agency's intent stated in the preamble (***emphasis added***)[54],

> *''[w]e believe that testing units that are not configured with a distinct combustion chamber* ***present several technical issues that are more optimally addressed through manufacturer testing****, and once these units are installed at a facility, through* ***periodic inspection and maintenance*** *in accordance with manufacturers' recommendations.*
>
> *[Text omitted for brevity.]*

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[54] 87 FR 74794

> *For these reasons, we believe the manufacturers' test is appropriate for these control devices with **ongoing performance ensured by periodic inspection and maintenance**. ["] (76 FR 52785; August 23, 2011).*

Given EPA's previous rationale for manufacturer testing, the monitoring requirements proposed under NSPS OOOOb, and the increased number of control devices subject to these monitoring requirements, API recommends that manufacturer-tested control devices continue to be exempt from periodic performance testing.

5.9 Enclosed combustion devices subject to minimum operating temperature and temperature monitoring should also be exempt from periodic performance testing.

Under MACT HH, combustion devices are exempt from periodic performance testing if the device demonstrates during initial performance testing that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 °C. NSPS OOOO requirements[55] changed this exemption to devices that meet the outlet TOC performance level and that establish a correlation between firebox or combustion chamber temperature and the TOC performance level. NSPS OOOOa[56] adds a temperature monitoring requirement to the NSPS OOOO exemption for control devices on centrifugal compressors.

Like manufacturer-tested devices, NSPS OOOOb proposes to remove this exemption from periodic performance testing. As such, enclosed combustion devices that demonstrate during initial performance testing that combustion zone temperature is an indicator of destruction efficiency are subject to a minimum operating temperature, periodic performance testing, and temperature monitoring. Given the consistent monitoring requirements proposed under NSPS OOOOb and the increased number of control devices subject to these monitoring requirements, API proposes that enclosed combustion devices for which temperature is correlated with destruction efficiency be exempt from periodic performance testing.

To clarify the requested exemptions from periodic performance testing, API offers the following suggested redline of §60.5413b(b)(4)(ii):

> *You must conduct periodic performance tests for all control devices required to conduct initial performance tests, except ~~for a control device whose model is tested under, and meets the criteria of paragraph (d)~~ as specified in paragraphs (b)(4)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(4)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420b(b)(12).*
>
> *(A) A control device whose model is tested under and meets the criteria of paragraph (d) of this section.*
>
> *(B) A combustion control device demonstrating during the performance test under paragraph (b) of this section that combustion zone temperature is an indicator of destruction*

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[55] §60.5413(b)(5)(ii)(B)
[56] §60.5413a(b)(5)(ii)(B)

efficiency and operates at a minimum temperature of 760 °Celsius or the minimum temperature established during the most recent performance test.

5.10 The continuous monitoring option for organic compound concentration in the control device exhaust may not be technically feasible or economically reasonable. This monitoring option is also meaningless without the corresponding outlet concentration performance standard.

As an alternative to continuous flow monitoring and other similar monitoring requirements, EPA has retained the existing option under NSPS OOOO and OOOOa to use a continuous monitor for organic compound monitoring in the control device exhaust. However, such monitoring may not be a technically feasible or economically reasonable alternative to the other continuous monitoring requirements.

Furthermore, this monitoring option does not make sense since the previous TOC outlet concentration performance standard was not proposed for NSPS OOOOb and EG OOOOc. EPA should clarify if the removal of this alternate performance standard was intentional and how operators should handle compliance for existing control devices that are complying with the TOC concentration standard under NSPS OOOO or OOOOa.

5.11 Technical clarifications for proposed control device requirements.

5.11.1 EPA should clarify requirements for regenerative carbon adsorption systems that use a regenerant other than steam.

For some existing regenerative carbon adsorption systems, residue gas or another regenerant is used instead of steam since the sites typically do not have access to a steam system like a chemical plant or refinery. In the natural gas production and processing industry, natural gas (mostly methane) with a set of heat exchange systems is used to regenerate the carbon beds in place of steam. These systems can be used when there is potential to have air enter the system. A carbon bed does not have a direct fire source which can help limit the potential for a fire in the system. The regeneration cycle is infrequent for these systems. While the proposed requirements for regenerative carbon adsorption systems are unchanged from NSPS OOOOa, EG OOOOc will subject existing sources and control devices to methane standards, and API would like to confirm these regeneration cycles would not be part of the control requirements under this rule. Operators should not be forced to change the operation of their existing control device provided they meet the applicable requirements. Forcing sites to switch to steam regenerant may be technically infeasible or economically unreasonable.

5.11.2 EPA should clarify the proposed requirement language around the presence of pilot flames.

The proposed requirements for control device pilot flames use the following three phrases, each of which could suggest a different meaning:

- A **"continuous burning pilot flame"** means a pilot flame is required at all times regardless of whether the site is operating or vent gas is sent to the control device.

- A **"pilot flame present at all times of operation"** could mean either a pilot flame is required at all times the site is operating or only for those times when the control device is operating (i.e., vent gas is sent to the control device)

- **"Pilot flame while emissions are routed to the control device"** means a pilot flame is required only when vent gas is sent to the device (in other words, at all times of control device operation).

A pilot flame should only be required when emissions are routed to the control device since loss of the pilot flame would result in additional emissions only when vent gas is sent to the device. This clarification would allow for the use of automatic ignition systems (see Comment 5.6.3). This clarification would also be consistent with the compliance requirement found at §60.5412b(b)(1):

> *You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*

API offers the following redlines that clarify a pilot flame should be required only when emissions are routed to the control device like some state rules including New Mexico[57]:

> *§60.5412b(a)(1)(vii): You must install and operate a continuous burning pilot flame or automatic ignition system.*
>
> *§60.5412b(a)(3)(iv): You must install and operate a continuous burning pilot flame or automatic ignition system.*
>
> *§60.5413b(e)(2): A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*
>
> *§60.5415b(f)(1)(vii)(A)(1): A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(d)(1)(i): For an enclosed combustion control device that demonstrates during the performance test conducted under §60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You also must comply with the requirements of paragraphs (d)(1)(viii)(D) and (E) of this section, and you must install a monitoring device that continuously (i.e., at least once every five minutes) indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(d)(1)(vii)(B): A monitoring device that continuously, at least once every five minutes, indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.*

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[57] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(c) NMAC

> *§60.5417b(d)(1)(viii)(A): Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times while emissions from affected facilities are routed to the control device. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.*

> *§60.5417b(g)(1): A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in §60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot flame or combustion flame present for any time period while emissions from affected facilities are routed to the control device.*

> *§60.5417b(g)(6)(iii): There is no indication of the presence of a pilot flame or combustion flame for any 5-minute time period while emissions from affected facilities are routed to the control device.*

> *§60.5420b(c)(11)(i)(F)(1): Records that the pilot flame or combustion flame is present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*

5.11.3 EPA should clarify which elements of the control device monitoring plan apply to heat sensing monitoring devices that indicate the presence of a pilot flame.

The proposed control device monitoring plan requirement includes the following exemption: "…*Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements of this section.*"[58] However, one of the listed monitoring plan elements uses a thermocouple as an example. This example is confusing since thermocouples could be used as a heat sensing monitoring device for a pilot flame, or as a temperature monitoring device. In the former case, the exemption would apply but not in the latter. EPA should clarify which elements of the monitoring plan apply to heat sensing devices.

Therefore, API recommends the following redline for §60.5417b(c)(2)(ii):

> *Sampling interface ~~(e.g., thermocouple)~~ location such that the monitoring system will provide representative measurements.*

Alternatively, EPA could propose a different example for sampling interface.

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[58] §60.5417b(c)(2)

5.11.4 EPA should clarify that control devices are not considered fugitive emissions components and how to address emissions from control devices detected during fugitive emissions monitoring.

While EPA recognizes that "control devices should not be treated as fugitive emissions components"[59], EPA adds confusion by trying to address emissions "caused by a failure of a control device subject to §60.5413b" under the alternative periodic screening requirements. API believes that this requirement is intended to address improper control device operation such as an unlit flare when vent gas is routed to it and recognizes that alternative periodic screenings can be an effective tool at identifying such issues. However, such emissions are not fugitive emissions and would not necessarily be part of the follow-up ground-based monitoring survey of fugitive emissions components or inspections of the cover and closed vent system. Since control devices are required to meet a 95% control efficiency, they will always have the potential for uncombusted emissions that could be detected by OGI or alternative technology. Unclear or inappropriate requirements related to detected emissions from control devices may be a disincentive for the use of alternative leak detection technologies. Therefore, EPA needs to reconsider how to better address emissions from control devices that could be detected during fugitive monitoring surveys. Refer to Comment 3.3.2 and Comment 3.4.6 for API's recommendations concerning follow-up action for alternative technologies.

5.12 Idle control devices at a site should be exempt from performance testing and monitoring requirements.

The proposed NSPS OOOOb and EG OOOOc requirements are unclear on whether idle control devices at a site are subject to performance testing and monitoring requirements. Some state rules, such as Colorado, require control devices be installed based on the potential maximum throughput of a site. For a site, the control devices may be installed and operated in series using pressure-activated valves, meaning that vent gas is sent to the first device until it reaches capacity before the excess vent gas is sent to the second device and so on. In actual operation, sites may never achieve the potential maximum throughput and associated emissions rates, so control devices toward the end of the control system are available but always idle. But even if activated, they would not be needed for purposes of complying with NSPS OOOOb or EG OOOOc.

One potential reading of the proposed NSPS OOOOb and EG OOOOc requirements is that such idle control devices are subject to initial and periodic performance testing and monitoring requirements especially if they are manifolded together. Conducting performance tests on idle control devices could increase in emissions since additional gas would need to be sent to the control devices for the purposes of testing or additional temporary piping installed to route vent gas to the idle control device. Furthermore, a failed performance test on an idle control device would force operators to repair, retrofit, or replace the device, increasing compliance costs with no environmental benefit because the idle device is not expected to be required for compliance. EPA recognized the environmental and cost disbenefit of testing idle emission sources in the federal standards for engines found in NSPS JJJJ[60] and MACT ZZZZ[61]. Similarly, installation of monitoring equipment on idle control devices increases costs with no environmental benefit.

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[59] 87 FR 74724

[60] §60.4244(b)

[61] §63.6620(b)

To clarify that idle control devices are exempt from performance testing and monitoring requirements, API offers the following redlines:

> *§60.5400b(a): General standards. You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas / vapor or light liquid service, and connector in gas / vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.*
>
> *§60.5401b(a): General standards. You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.*
>
> *§60.5412b: You must meet the requirements of paragraphs (a) and (b) of this section for each control device ~~used to comply~~ operated for the purpose of complying with the emissions standards for your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.*
>
> *§60.5412b(a): Each control device ~~used to meet~~ operated for the purpose of complying with the emissions reduction standard in §60.5377b(b) for your well affected facility, §60.5380b(a)(1) for your centrifugal compressor affected facility; §60.5395b(a)(2) for your storage vessel affected facility; §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska; or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (a)(3) of this section. As an alternative to paragraphs (a)(1) through (a)(3) of this section, you may install a control device model tested under*

> *§60.5413b(d), which meets the criteria in §60.5413b(d)(11) and which meets the initial and continuous compliance requirements in §60.5413b(e).*
>
> *§60.5412b(b)(1): You must operate each control device ~~used to comply~~ operated for the purpose of complying with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*
>
> *§60.5417b: You must meet the requirements of this section to demonstrate continuous compliance for each control device ~~used to meet~~ operated for the purpose of complying with emission standards for your well, centrifugal compressor, pneumatic controller, storage vessel, and process unit equipment affected facilities.*
>
> *§60.5417b(a): For each control device ~~used to comply~~ operated for the purpose of complying with the emission reduction standard in §60.5377b(b) for well affected facilities, §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section.*

5.13 The monitoring plan for control devices does not need to be site-specific.

EPA is proposing that each control device have a site-specific monitoring plan to address the monitoring system design, data collection, and quality assurance / quality control elements. Operators may install the same control device and associated monitoring system across sites in one or more company-defined areas. Similar to the fugitive monitoring plan requirement, EPA should allow monitoring plans for control devices to be based on a company-defined area or a company-wide plan for a specific make and model of control device. Like the fugitive monitoring techniques, control device monitoring is based on the type of control device and monitoring system rather than the site itself. Requiring practically identical site-specific monitoring plans for the large number of control devices increases the administrative burden for operators with no environmental benefit.

5.14 The first repair attempt timeline for covers and closed vent systems may be impractical for certain locations.

While EPA has retained the existing NSPS OOOOa requirements[62] for a first repair attempt on leaks detected from covers or closed vent systems, the 5-day timeline will apply to significantly more sites under NSPS OOOOb and EG OOOOc than NSPS OOOO and OOOOa. This requirement may be impractical for some sites that have access limitations such as those on leased farmland. While API recognizes the historic importance and priority of repairing leaks on covers and closed vent systems, a longer timeline, such as 15 or 30 days, may be more pragmatic since the number of regulated covers and closed vent systems will increase significantly under NSPS OOOOb and EG OOOOc requirements. A different first repair attempt timeline could have the added benefit of

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[62] §60.5416a(b)(9) and §60.5416a(c)(4)

making repair timelines consistent between fugitive emissions components and covers and closed vent systems, thus streamlining compliance for operators.

6.0 Storage Vessels

API supports EPA's proposed 6 tpy VOC and 20 tpy methane thresholds for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. We also support EPA's retention of the current alternate control standard to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC and 14 tpy methane. With some technical clarification concerning location, API agrees with EPA's proposed definition for a tank battery.

However, API has concerns regarding EPA's proposed criteria for legally and practically enforceable limits, the proposed definition of modification, and some of the proposed operational requirements. These items are detailed in the following section.

6.1 EPA's proposed criteria for legally and practicably enforceable limits have legal implications beyond this rulemaking and pose permitting challenges.

EPA's proposed requirements for legally and practicably enforceable limits also have legal implications beyond this rulemaking, and these restrictions violate the concept of cooperative federalism. EPA's proposed revisions are wholly inconsistent with EPA's reliance on states to administer the Clean Air Act with regard to Title V and PSD. That is, EPA allows states to establish emission limits on sites that keep sites below Title V and PSD permitting thresholds. EPA should continue to defer to states to determine the appropriate level of monitoring, recordkeeping, and reporting requirements to include in permits rather than imposing a list of strict criteria. This has long been an effective approach to reduce recordkeeping burden while reducing potential emissions.

Just as important as the legal implications discussed in Comment 12.10, the proposed criteria for legally and practicably enforceable limits provide no additional benefit and pose several permitting challenges. Existing permits and associated state programs and rules likely do not meet all the required criteria since EPA has historically deferred to the states on the sufficient monitoring, recordkeeping, and reporting requirements to include in the various levels of permits. For example, permits have proposed annual or rolling 12-month limits on emissions and production since the tank PTE thresholds and NSR permitting thresholds are based on annual emissions. EPA should clarify that such annual limits meet the proposed 30-day averaging time for production limits especially since facilities are typically permitted for a worst-case scenario. Another criterion likely not in existing permits is "*periodic reporting that demonstrates continuous compliance*". Historically, periodic reporting has applied to major sources under Title V and affected facilities regulated under a NSPS or National Emission Standards for Hazardous Air Pollutants (NESHAP), which is a small fraction of the sites that will be regulated under NSPS OOOOb and EG OOOOc. Monitoring, recordkeeping, and reporting requirements in a permit should be tailored to align with the level of authorization with minor sources having less requirements than major sources. For streamlined permitting mechanisms, such as Permits by Rule in Texas, the state agency would have to engage in rulemaking before operators could rely on such permits for determining storage vessel and tank battery PTE. Such rulemaking could take months to years, meaning that operators cannot rely on legally and practicably enforceable limits until those rule updates are finalized and effective.

The second permitting challenge is the methane emissions threshold. For permitting, methane is typically regulated as a greenhouse gas for major sources under the PSD program. States may not be able to permit a methane limit under their minor NSR programs. As such, EPA should clarify that a methane emission limit is not required to be explicitly listed in the permit provided the control device and/or production limits are included that would limit the PTE from a storage vessel or tank battery to less than 20 tpy of methane. Another approach is to allow a VOC limit of less than 6 tpy to serve as a surrogate for the methane emission limit. A potential consequence of requiring an explicit methane emission limit is that existing tanks may have a permit that does not make them an affected facility under NSPS OOOO or NSPS OOOOa but will not be able to obtain an updated permit for the purposes of EG OOOOc applicability.

Assuming operators can obtain permits that meet the proposed legally and practicably enforceable criteria, the permitting effort for the hundreds of thousands of existing storage vessel designated facilities potentially subject to EG OOOOc will take years and be an administrative burden on operators and the state permitting authorities with no environmental benefit. One member has estimated that it will take ten (10) years to obtain updated permits at the current preparation and agency review timelines. This estimated effort will likely take longer as other operators also seek to update permits at the same time. Given the potential enormous re-permitting burden for existing storage vessels/tank batteries, EPA should allow operators to rely on VOC limits as a surrogate for methane in existing permits that have previously been understood to be legally and practicably enforceable.

Overall, EPA’s proposed requirements for legally and practicably enforceable limits have broad legal implications and impose real permitting challenges. The combined effect is contrary to the historical intent under NSPS OOOO and NSPS OOOOa, which is to lessen the administrative burden while still achieving the desired environmental benefits. API believes that improving the clarity of the storage vessel applicability criteria is a worthwhile effort and offers the following redline for §60.5365b(e)(2)(i):

> *For purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit ~~must~~ may include the elements such as those provided in paragraphs (e)(2)(i)(A) through (F) of this section.*

6.2 The proposed requirements for a modification and reconstruction of a tank battery require additional technical clarifications.

EPA’s proposed definitions of reconstruction or modification for a tank battery require several clarifications. First, the proposed definition for reconstruction is internally inconsistent. For a tank battery consisting of more than one storage vessel, reconstruction is based on replacing at least half of the storage vessels based on the assumption that “*the cost of replacing storage vessel components such as thief hatches and pressure relief devices, in comparison to the cost of constructing an entirely new storage vessel affected facility, will not exceed 50 percent of the cost of constructing a comparable new storage vessel affected facility*.”[63] However, for a tank battery consisting of a single storage vessel, the existing provisions of §60.15 apply on the chance that the cost of replacement storage vessel components could be 50% or more of the cost to construction a comparable new storage vessel. Either the cost depreciable components on a storage vessel other than the tank itself could be 50% or more of the cost of a new comparable tank or not. Practically, this inconsistency means that operators would have to track the cost of storage vessel component replacements for single storage vessel tank batteries, but not for multi-vessel tank batteries. For both single and multi-vessel tank batteries, operators should have the option

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[63] 87 FR 74801-74802

to track either storage vessel replacements or all depreciable components. Based on this recommendation, API offers the following redline of §60.5365b(e)(3)(i):

> *"Reconstruction" of a tank battery occurs when the provisions of §60.15 are met for the existing tank battery ~~any of the actions in paragraphs (e)(3)(i)(A) or (B) of this section~~ and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section. As an alternative to the provisions of §60.15, an operator may determine reconstruction has occurred if at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> *~~(A) The provisions of §60.15 are met for the existing tank battery ; as an alternative to the provisions of §60.15, At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or~~*
>
> *~~(B) The provisions of §60.15 are met for the existing tank battery that consists of a single storage vessel.~~*

Secondly, EPA's proposed definition of modification requires clarification. API supports the first two proposed criteria for modification found in §60.5365b(e)(3)(ii)(A) and (B): "*A storage vessel is added to an existing tank battery*" and "*One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases*". Both these changes require capital expenditure on the potential affected facility (i.e., the tank battery) and would increase emissions. However, the proposed criteria in §60.5365b(e)(3)(ii)(C) and (D) regarding increases in liquid throughput are too broad and is inconsistent with §60.14(e)(2). Per 40 CFR 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification. EPA has not fully explained why it is proposing to deviate from the historical legal understanding of modification which requires both an increase in throughput and a capital expenditure on the storage vessel or tank battery. Also, increases in liquid throughput at well sites, central production facilities, and compressor stations are difficult to track as sites typically track liquid throughput using tank gauging rather than flow meters. Due to the historic understanding of modification and practical challenges of tracking liquid throughput, **API believes that §60.5365b(e)(3)(ii)(C) and (D) should be removed from the definition of modification**. [64]

However, if EPA decides to include increases in liquid throughput as a criterion for modification, API offers the following recommendations:

- **The increase in liquid throughput must also be accompanied by a capital expenditure on the tank battery itself.** Actions, such as drilling a new well or fracturing or refracturing an existing well, could increase liquid throughput and require capital expenditure but not necessarily on the tank battery itself.

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[64] Please see Section 11.6 of our comments on the original proposal for overarching legal comments on the proposed modification definitions. We note that EPA appears to have responded in part to these comments by providing that a modification to a tank battery occurs only when specified actions "result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii)" (the PTE-based applicability thresholds for storage vessels). But we note that EPA's proposed PTE criteria apply to an annual PTE and not, as specified in § 60.14, a short-term measure of PTE (such as lb/hr). This is a significant change in how a potential emissions increase should be considered in determining the existence of a modification because the annual PTE basis in practice likely results in a more expansive modification definition because the short term PTE of storage vessels in almost all cases will be much higher than an annual value, which means that more variation in actual short term emissions can be accommodated without triggering a modification than under an annual metric. EPA fails to explain why it has shifted from a short-term to an annual basis for determining emissions increases associated with a change. As a result, we do not have a reasonable opportunity to understand EPA's rationale and to provide meaningful comments.

These actions would not be considered modifications to the tank battery unless there is capital expenditure on the tank battery itself. This recommendation would make NSPS OOOOb consistent with NSPS A.

- **Reference to process unit in §60.5365(e)(ii)(C) should be removed since process unit is defined such that they should not exist at well sites and centralized production facilities.** Process unit is a term specific to natural gas processing plants and does not apply to well sites and centralized production facilities.

- **Well sites and centralized production facilities should also be allowed to compare liquid throughputs to limits in a legally and practicably enforceable permit like compressor stations and natural gas processing plants.** EPA should be consistent and allow well sites and centralized production facilities to compare liquid throughputs to limits in a legally and practicably and enforceable permit since such a permit can be relied upon for the PTE determination for all sites. **In the absence of a legally and practicably enforceable limit, all sites should be allowed to compare liquid throughputs to those used to design the existing cover and closed vent system in operation when a potential modification action occurs.** These recommendations would also make modification criteria consistent for all sites and clearly define what an increase in liquid throughput is.

Based on these recommendations, API offers the following redlines to §60.5365b(e)(3)(ii):

> *"Modification" of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through ~~(D)~~(C) of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> *(A) A storage vessel is added to an existing tank battery;*
>
> *(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; or*
>
> *~~(C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well).~~*
>
> *~~(D)~~(C) ~~For tank batteries at compressor stations or onshore natural gas processing plants,~~ A capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or ~~(D)~~(C) of this section) determination of the potential for VOC or methane emissions; or in the absence of a legally and practicably enforceable permit, a capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or (C) of this section) design of the storage vessel cover(s) and closed vent system.*

6.3 Additional technical clarifications to proposed definitions are warranted to clarify applicability of certain requirements for tank batteries.

Since the proposed requirements for NSPS OOOOb and EG OOOOc will apply for the tank battery, there are additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria. We support EPA's proposed definition for tank battery based on storage vessels that are manifolded together for liquid transfer, but offer a minor clarification on respect to its location as follows:

> *Tank battery means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant if only one storage vessel is present.*

This clarification addresses the situation of a single storage vessel not located at a well site, central production facility, compressor station, or natural gas processing plant (e.g., drip station along a pipeline). These storage vessels typically have low throughput and methane and VOC emissions. In §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii), EPA does not describe how to determine PTE for tank batteries at location other than a well site, centralized production facility, compressor station, or natural gas processing plant. Therefore, API believes that the agency did not intend to regulate these low-emitting tanks with these proposed rules.

6.3.1 The definition of compressor station must be clarified with respect to the storage vessel applicability provisions in §60.5365b(e).

With the introduction of the newly defined central production facility, an additional clarification is needed for when and how to calculate the tank battery PTE at well sites and central production facilities that may have compression versus at a compressor station. The EPA makes this distinction clearly for how to consider the fugitive emission monitoring by referencing §60.5397b in the definition of compressor station. As an example, consider a reciprocating compressor at an oil processing facility. The facility would be a "*tank battery at a well site or centralized production facility*" under §60.5365b(e)(2)(ii) and yet also a "*tank battery located at a compressor station*" as used in §60.5365b(e)(2)(iii).

We therefore request EPA also clarify the storage vessel requirements in a similar way by referencing of §60.5365b(e) in the definition of compressor station as follows:

> *Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of §60.5365b(e) and §60.5397b.*

In terms of the PTE calculations, centralized production facilities should be considered like compressor stations and natural gas process plants because the storage capacity is typically based on "a projected maximum average daily throughput". Therefore, API offers the suggested redlines for §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii).

> *(ii) For each tank battery located at a well site ~~or centralized production facility~~, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided*

> *in paragraph (e)(5)(iv) of this section. The potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.*
>
> *(iii) For each tank battery located at a centralized production facility, compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station or onshore natural gas processing plant or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.*

Another suggested solution is to harmonize the PTE calculation requirements for all sites based on the requirements proposed for compressor stations and gas plants.

6.3.2 A storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant used to alleviate dangerous, or emergency events must be clearly excluded from the definition of storage vessel.

At some facilities, storage vessels may be installed for the sole purpose of providing relief from pressure vessels during emergencies. Previously, these storage vessels would not trigger applicability as a single emergency use vessel was unlikely to exceed 6 tpy VOC threshold under NSPS OOOO or NSPS OOOOa. These tanks now present a challenge with the new applicability threshold proposed in NSPS OOOOb and EG OOOOc for the tank battery. At the state level, emergency use tanks are exempt from control requirements from states and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.[65,66] We request EPA provide an exclusion for emergency use tanks from the definition of storage vessel as follows:

> *Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:*
>
> - *Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180*

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[65] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[66] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

- *Process vessels such as surge control vessels, bottoms receivers or knockout vessels.*
- *Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.*
- *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

6.3.3 EPA should clarify that location is not a restriction on the use of a floating roof tank.

In §60.5395b(b)(2), EPA correctly prohibits the use of a floating roof if the storage vessel or tank battery has flashing emissions. However, EPA also prohibits the use a floating roof at a well site or centralized production facility. Flashing emissions alone, regardless of location, should prohibit the use of a floating roof tank because flashing emissions, not location, could prevent proper operation of a floating roof.

API offers a recommended redline in Comment 6.5.

6.4 The requirement to manifold the vapor space of each storage vessel in the tank battery is overly prescriptive and unnecessary.

As part of the control requirements for storage vessel affected facility, EPA proposes that "*The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery*"[67]. This requirement to manifold the vapor space of each storage vessel in a tank battery is unnecessary and restricts an operator's flexibility in achieving compliance with the required 95% emissions reduction. An operator should be able to install any number of control devices and manifold the vapor space of the storage vessels from one or more tank batteries into one or more closed vent systems so that each control device is properly sized for the expected vent gas flow rate.[68] The requirement to manifold the vapor space of a tank battery may also cause confusion with the proposed definition of tank battery which is based on storage vessels manifolded together for liquid transfer.

API offers a recommended redline in Comment 6.5.

6.5 EPA should provide an exemption from control requirements due to technical infeasibility if the control device or VRU would require supplemental fuel.

With the change in affected facility from a single storage vessel to a tank battery, control devices will be required for a longer time compared to NSPS OOOO and NSPS OOOOa – until the actual uncontrolled emissions from the tank battery (versus each individual storage vessel) are below 4 tpy VOC and 14 tpy of methane. This longer

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[67] §60.5395b(b)(1)(ii)

[68] If not corrected, EPA's failure to consider these obvious and important aspects of its proposed manifolding requirement would render such a requirement arbitrary and capricious. Motor Vehicle Mfrs. Assn. v. State Farm Mut. Automobile Ins. Co., 463 U.S. 29, 43 (1983).

period for the control requirement will increase the likelihood that some control devices or VRUs will require supplemental fuel to be technically feasible. As discussed in Comment 5.6.3 for control device pilot flames, operators may have to bring propane for supplemental fuel for sites without fuel gas or burn additional sour fuel gas. As such, API recommends EPA consider an exemption from control requirements for a tank battery if use of a control device or VRU would be technically infeasible without supplemental fuel for pilot flame or other purposes. Such exemptions currently existing in state regulations for storage vessels and tank batteries including Colorado. Based on the language for the Colorado exemption, API offers the following recommended redlines to the control requirements in §60.5395b(b), which also includes the previous comment:

Control requirements.

(1) Except as required in paragraphs (b)(2) and (b)(3) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through ~~(iv)~~ (iii) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);

~~(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;~~

~~(iii)~~(ii) The tank battery must be equipped with ~~a~~ one or more closed vent systems that meet~~s~~ the requirements of §60.5411b(a) and (c); and

~~(iv)~~(iii) The vapors collected in paragraph~~s~~ (b)(1)(ii) ~~and (iii)~~ of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) For storage vessel affected facilities that do not have flashing emissions ~~and that are not located at well sites or centralized production facilities~~, you may use a floating roof to reduce emissions. If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb. You must submit a statement that you are complying with §60.112b(a)(1) or (2) with the initial annual report specified in §60.5420b(b)(1) and (8).

(3) You may apply to the Administrator for an exemption from the control requirements in paragraphs (b)(1) of this section if the use of a control device would be technically infeasible without supplemental fuel. Such request must include documentation demonstrating the infeasibility of the control device.

7.0 Natural Gas-Driven Pneumatic Controllers

Pneumatic controllers play a pivotal role in the safe operations at oil and natural gas facilities – including at well sites, central productions facilities, compressor stations, and processing plants. In our review of the proposed requirements EPA has not adequately addressed some of the major concerns we identified in our January 31, 2022 comment letter.[69] EPA has severely overstated the deployment capabilities for solar installations to power oil and gas infrastructure in support of their proposal, which indicates a continued lack of understanding of how pneumatic controllers (and pneumatic pumps) would be converted to achieve a non-emitting standard.

For NSPS OOOOb, we support the use of non-emitting pneumatic controllers, contingent on clarifications as described herein, for newly constructed, modified or reconstructed well sites, central production facilities, and compressor stations. We also support EPA excluding emergency shutdown devices from these provisions as it allows for safety in case of emergency.

For existing natural gas-driven pneumatic controllers under NSPS OOOOc, we continue to maintain that 1) adequate time and phase-in must be provided to properly account for the magnitude and scale of sites converting to non-emitting controllers and 2) it is most appropriate to focus conversion to non-emitting controllers at facilities with the largest number of controllers (see Comment 7.5). To effectively do this, the use of low continuous bleed or intermittent natural gas-driven pneumatic controllers should be allowed and should be monitored periodically for proper functioning at the frequency specified in §60.5397c. An initial analysis[70] of the potential impact of the rule should it require conversion to non-emitting pneumatic controllers at all existing facilities shows that it could result in the premature shut-in of a significant percentage of existing wells, particularly when considered in context with the proposed monitoring requirements[71]. EPA should allow additional flexibility in this area as we have described to allow states to preserve the remaining useful life of facilities.

7.1 Adequate implementation time must be provided for pneumatic controller and pneumatic pump requirements under both NSPS OOOOb and EG OOOOc.

As we have stated earlier, adequate time is required to implement the proposed control standards as they fundamentally shift how pneumatic controllers and pneumatic pumps have typically been operated. While new surface locations can typically plan for controls during site design, the supply chain delays pose a genuine and significant concern for all aspects of implementing the pneumatic controller requirements. Anecdotal evidence from one operator that is currently conducting retrofits in New Mexico has identified that air compression equipment is in short supply with around 8 months of delays and another operator that has been piloting solar panel instrument air systems is now experiencing delays of 18 to 24 months on previously made orders. While eventually the market will rise to meet this demand, that market correction has not yet been realized and presents very real concerns for our members. Currently there are hundreds of operators attempting to order equipment for thousands of sites. While we are generally supportive of the proposed requirements (with the necessary and specific clarifications that we have requested), the current proposed timeline for compliance is unrealistic due to global circumstances beyond any operator’s ability to control or influence.

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[69] EPA-HQ-OAR-2021-0317-0808

[70] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API’s request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

[71] See Comment 2.0

As anecdotal evidence, our members operating in New Mexico are currently working through retrofits of facilities in compliance with state regulations. Instrument air systems are currently on backorder with a wait time of approximately 8 months. This wait time is expected to be exacerbated when EPA's final rule takes effect. Once equipment is received, only 1-3 facilities can be retrofit per operator per week based on type or size of the facility, weather conditions, etc. This means for any given operator, only approximately 50-150 retrofits can successfully take place in a single year. For operators with thousands of new, modified and existing locations, the current proposed timelines are untenable.

Based on EPA's proposed November 2021 applicability date, there are thousands of sites that may now require retrofit under NSPS OOOOb. Since operators are currently experiencing 6-to-8-month delays in acquiring the necessary control equipment for instrument air system conversions, we suggest EPA amend the requirements to reference "upon receipt of equipment" similar to how certain delay of repair provisions have been framed within other regulations.

For pneumatic controllers and pumps under EG OOOOc, given all of the existing sites in the U.S. and the implementation aspects outlined above, we continue to have serious concerns that 5 years for conducting retrofits of this magnitude would not provide adequate time given current and anticipated supply chain delays. Because of these constraints for EG OOOOc, EPA should consider a longer phase-in period where facilities with the largest number of controllers are retrofit first.

7.2 For NSPS OOOOb and EG OOOOc, EPA should allow the routing of emissions from natural gas-driven controllers to a control device.

We continue to suport the routing of certain controller emissions to a flare or other combustion device. In its analysis, EPA dismisses this option by finding that routing pneumatic controller vent gas to a process is cost-effective and thus BSER; however, EPA's analysis fails to account for the cost-effectiveness of the incremental 5% of methane and VOC emissions reductions achieved when comparing routing to process against routing to a control device, which conservatively assumes a control device will achieve only 95% reduction.[72] In many cases, the actual performance of a control device exceeds 98% control. Instead, EPA's analysis focuses on the cost-effectiveness of no control against 100% control. API requests that EPA include routing to a control device as a compliance standard under NSPS OOOOb and EG OOOOc. If EPA does not adopt routing to a control device as an emissions reduction standard, it must demonstrate as cost-effective the incremental 5% of emissions reductions achieved through routing to a process or converting to instrument air.[73]

As an example, one facility may choose to install an instrument air system to convert most natural gas-driven pneumatic controllers on site, but emissions from certain types of controllers that are associated with the flare system itself (e.g. back pressure valve[74]) could more easily route emissions to the flare header. By EPA not allowing for this site configuration, some operators may need to reconfigure controllers that are currently already

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[72] 87 Fed. Reg. at 74765-66.

[73] As further support for the above, API responds to EPA's request for information regarding whether vapor recovery units (VRU) are ever necessary to route pneumatic controller vent gas to a process. While it is feasible for operators to route pneumatic controller vents to a downstream process that operates at a lower pressure, a VRU is necessary if no such lower-pressure destination exists or is of limited availability. Installation of a VRU is capital intensive, and VRU maintenance is costly and challenging, especially in extreme weather climates. Where downstream process pressure exceeds vent gas pressure, the pneumatic controller vent gas cannot feasibly route to a downstream process without compression. If EPA is unwilling to allow routing of pneumatic controller vent gas to a control device as an emissions reduction standard on the same footing as routing to a process, EPA should allow routing to a control device where routing to a process is infeasible (taking into account technical and economic considerations), and define infeasibility to include scenarios where routing to a process requires a VRU.

[74] Back pressure valves can be routed to the flare when they are in close proximity to the flare header since they only actuate when there is an over pressurization.

routed to a flare or other combustion device. In this scenario, VOC and methane emissions from these routed controllers are already reduced by 95% or more. EPA has provided no basis for not authorizing routing to control as an option.

Adopting this methodology as a compliance standard can be achieved by amending the proposed definition of “self-contained pneumatic device” to include natural gas-driven controllers routed to control devices in that definition (refer also to Comment 7.3). Such a revision is consistent with both New Mexico and Colorado’s regulations – which define non-emitting to include pneumatics routed to combustion.

7.3 Additional technical clarifications are warranted to clarify applicability of certain natural gas-driven pneumatic controller requirements.

While we support inclusion of flexible solutions to reduce emissions from natural gas-driven pneumatic controllers, we have identified critical aspects of the proposed provisions that require technical clarification or simplification as we have outlined herein.

7.3.1 Suggested clarifications to certain proposed definitions related to pneumatic controllers in NSPS OOOOb and EG OOOOc.

There are some additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria as proposed. There are many types of automated instruments that maintain a process condition that are not pneumatic controllers. Many of the proposed definitions must clearly identify pneumatic controllers from these other instruments and be more specific to avoid confusion.

> ***Bleed rate*** *means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a fixed orifice in a pneumatic controller.*
>
> ***Continuous bleed*** *means a natural gas-driven pneumatic controller that is designed with a continuous flow of ~~pneumatic supply~~ natural gas from ~~to~~ a fixed orifice~~ pneumatic controller~~.*
>
> ***Non-natural gas-driven pneumatic controller*** *means an automated process control device that utilizes instrument air or hydraulic fluid as the motive force to change valve position. ~~Instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.~~*
>
> ***Pneumatic controller*** *means an automated instrument that manipulates a valve’s position with pressurized gas to ~~used for~~ maintain~~ing~~ a process condition such as liquid level, pressure, delta-pressure and temperature.*
>
> ***Self-contained pneumatic controller*** *means a natural gas-driven pneumatic controller in which the motive gas is not vented to the atmosphere but captured ~~releases gas~~ into t~~he~~ downstream piping for process use, sales or control such that there are no direct methane or VOC emissions from the controller.~~, resulting in zero methane and VOC emissions~~*

7.3.2 EPA must clarify the pneumatic controller requirements in NSPS OOOOb and EG OOOOc apply after startup of production and to stationary equipment only.

We agree with EPA'a assertion in the preamble where (87 FR 74759) *"The EPA acknowledges that the focus of the BSER analysis has been on stationary sources and pneumatic controllers that are part of the routine operation of oil and natural gas facilities."* The zero-emissions requirements are not justified for short term controller usage related to non-stationary sources.[75] Retrofitting controllers located on temporary equipment requires significant engineering design that has not been adequately evaluated to identify if these options are even possible, nor technically achievable nor practically attainable. Pneumatic controllers located on temporary or portable equipment should be allowed to operate as low-bleed or intermittent as needed for proper functioning of the temporary equipment. Some examples of temporary equipment or activities that should be excluded from the proposed provisions include the following:

- **Temporary Equipment (such as compressors):** Operators may utilize a small injection compressor to assist in ramping up production for new wells that have recently ended flowback. These compressors are typically skid mounted and located on site for as few as 30 days after the startup of production. These compressors contain a handful of pneumatic controllers to assist in proper function on the unit and may sometimes be leased from a third party. Another example is the use of a temporary compressor at a wellsite that is needed in anticipating gathering system high line pressure during new gathering system infrastructure build-out, which may occur for a few months. We ask that EPA exclude any natural gas-driven pneumatic controllers on equipment that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 180 consecutive days. This approach is consistent with language describing applicability of temporary storage vessels under NSPS OOOO, NSPS OOOOa, proposed NSPS OOOOb, and proposed EG OOOOc.

- **Drilling and Completion Activities:** As EPA is aware, drilling and completion activities require specialized temporary use equipment that is often contracted by third-party operators. Any pneumatic controllers associated with drilling and completion equipment should be excluded from the zero-emitting controller requirements, which can be accomplished by clarifying that the requirements for pneumatic controllers are not applicable until after the startup of production like other provisions within the proposed standards.

7.3.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic controllers.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms 'natural gas-driven pneumatic controller' and 'pneumatic controller' interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic controllers. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric controllers at the well site as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(d)(1):

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[75] Exemption of controllers on temporary equipment is consistent with state regulations in New Mexico and Colorado.

> *For the purposes of §60.5390b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more.*

We offer a suggested redline for reconstruction below in Comment 7.3.4.

To be clear, our support for the proposed provision as it relates to modification for natural gas-driven pneumatic controllers is contingent on this and the other clarifications requested throughout Comment 7.3. Absent these clarifications then we maintain our previous position submitted in our January 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) and request EPA streamline applicability across various affected facilities by defining modification for the collection of natural gas-driven pneumatic controllers and pneumatic pumps like how EPA has defined modification for the collection of fugitive components at well sites and compressor stations. For central production facilities, modification should be based on an increase in designed throughput capacity with the addition of a storage vessel at the central production facility as we further elaborate in Comment 2.6.

7.3.4 Under NSPS OOOOb, reconstruction for natural gas-driven pneumatic controllers should not include replacement of a high-bleed natural gas-driven controller with a low-bleed or intermittent controller.

Many of our members have committed to the elimination of all remaining high-bleed controllers that may still be in use at existing locations. As we included in our January 31, 2022 comment based on data submitted to EPA through EPA's Greenhouse Gas Mandatory Reporting Program, data extracted for the 2020 calendar year clearly shows the breakdown of high-bleed natural gas-driven pneumatic controllers is only around 2% of total reported natural gas-driven pneumatic controllers across both the onshore production segment and onshore gathering and boosting segments. This indicates there are not many high-bleed devices left in operation at well sites, central production facilities, and compressor stations based on successful implementation of NSPS OOOO and NSPS OOOOa over the last decade.

Replacement of these last remaining high-bleed controllers with low-bleed or intermittent controllers would equate to an overall reduction in methane and VOC emissions and should not be included in the reconstruction provisions as this could disincentivize short term benefits of this type of replacement. With the implementation of EG OOOOc coinciding with proposed NSPS OOOOb, this clarification will only delay conversion to non-emitting without impacting current investment in equipment upgrades in the near term that provide immediate environmental benefit.

We offer the following suggested redline to §60.5365b(d)(2) to address these concerns and the clarification explained in Comment 7.3.3:

> *§60.5365b(d)(2): For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of existing natural gas-driven pneumatic controllers at the site in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic controllers is replaced. That is, if*

an owner or operator meets the definition of reconstruction through the "number of controllers" criterion in (d)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of natural gas-driven pneumatic controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic controller replacement. Replacement of an individual natural gas-driven controller with a continuous bleed rate greater than 6 scfh with either a natural gas-driven controller with a continuous bleed rate less than 6 scfh or with an intermittent vent natural gas-driven pneumatic controller is excluded from this determination.

If the owner or operator applies the definition of reconstruction in §60.15(b)(1), reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven pneumatic controllers at the site. The "fixed capital cost of the new pneumatic controllers" includes the fixed capital cost of all natural gas-driven pneumatic controllers which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic controllers that are replaced, the owner or operator must also comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review.

7.3.5 Additional clarifications are required to the proposed requirements for reconstruction of pneumatic controllers.

In review of the proposed regulatory text provided for §60.5365b(d)(2), the following are elements of the proposed regulatory text require clarification.

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed in §60.5365b(d)(2).** The proposed language in §60.5365b(d)(2)(ii), suggests that reconstructed natural gas-driven pneumatic controllers would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic controllers. We believe it was EPA's intent to

not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 Supplemental Proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 Supplemental Proposal.

7.4 Self-contained natural gas-driven controllers should follow the requirements for fugitive emission monitoring, not those for closed vent systems.

Self-contained natural gas-driven pneumatic controllers are configured to route emissions into the downstream piping, which is simply a hard piece of pipe with connectors or flanges. Given the simplicity and low potential for leaks or defects along the piping, EPA is correct in allowing OGI inspections, but we believe operators should follow the work practice for the fugitive emission monitoring requirements §60.5397b and not the NIE provisions as proposed.[76] EPA should also allow inspection of self-contained pneumatic controllers via the alternative screening techniques program, when applicable.

We also note that as proposed, the self-contained pneumatic controller requirements do not articulate repair or contain delay of repair provisions or timelines and we believe this was not EPA's intent. Given self-contained pneumatic controllers would more commonly occur on pressure control valves, the operator would likely need to shut-in the well or shutdown equipment in order to conduct any sort of repair (if any were found). We therefore request, at a minimum, that repair timelines in §60.5397b(h) and specifically the delay of repair provisions as described in §60.5397b(h)(3) apply to self-contained natural gas-driven pneumatic controllers.

As we mention in Comment 2.4, we encourage EPA to streamline how periodic monitoring in the proposed rules is conducted by following a consistent set of requirements including the frequency, repair schedule, and retention of associated records. This will provide clarity across all affected facilities at a site where monitoring is occurring.

7.5 For EG OOOOc, locations without access to electrical power should have the option to use low continuous bleed or intermittent bleed natural gas-driven pneumatic controllers with proper functioning confirmed through periodic monitoring until modification or reconstruction triggers NSPS OOOOb. At a minimum, EPA must consider an allowance for low production well sites and/or sites with a limited number of natural gas-driven controllers from retrofit within EG OOOOc.

Many existing well sites are low producing wells that could be close to end-of-life of their production cycle and may only contain a limited number of controllers. The complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production versus implementation of the collective costs associated with EG OOOOc. The BLM acknowledged this fact in their proposed Waste Prevention Rule by establishing an exemption of retrofit of pneumatic controllers based on facilities *"producing at least 120 Mcf of gas or 20 barrels of oil per month"* because *"it is unlikely that an*

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[76] Should EPA continue to apply NIE as a numerical standard for self-contained pneumatic controllers, it could disincentivize conversion.

operator of a lease, unit, or CA producing only 120 Mcf of gas or 20 barrels of oil per month could re-direct the entirety of its revenues for 10 months towards paying for upgrading its pneumatic equipment."[77]

In our previous comment letter submitted January 2022, we supported retrofit for facilities with at least 15 controllers at a well site, central production facility, or compressor station. There have not been any drastic changes in actual costs to retrofit facilities or technical feasibility of implementing these types of retrofits in locations that do not have access to grid power. In fact, due to other similar regulations currently being implemented at the state level, the timeline for acquiring the necessary equipment is long due to supply chain limitations, and skilled labor is in short supply and high demand. We maintain our position that at these existing facilities any high-bleed natural gas-driven pneumatic controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company's fugitive emission monitoring program to monitor for proper functioning. The recordkeeping and reporting for these devices should follow requirements associated with fugitives and not have a separate set of requirements as currently proposed for sites in Alaska.

7.5.1 Spacing constraints at existing sites may cause technical infeasibility for converting to non-emitting controllers where grid power is not available.

Existing well site sites, central production facilities or compressor stations may have sizing constraints for the proper placement (due to safety and other permitting constraints) of instrument air control systems. Examples include an instrument air compressor that must sit outside of classified areas, generators, and/or or solar panels.

To retrofit a facility with an instrument air system, an engineer first verifies that adequate power is available and then applies for necessary state level permits, which takes approximately 60 days to acquire (if approved). On federal lands, this type of project would require reopening permits pursuant to National Environmental Policy Act, which is around a 12 to 18 month permitting process. On private lands, an operator may not be able to purchase additional land from the private owner.

During construction, an instrument air header and compressor skid must be added to the facility. The air compressors must sit outside of classified areas and therefore, some older reclaimed facilities may not have adequate space to add necessary equipment for the instrument air system because the air compressor must be placed outside of a safe radius from existing flares and other hydrocarbon-containing equipment (e.g. limitations due to electrical classifications). If accessible grid power is not available, a generator would have to be installed to power the air compressor, which would emit other pollutants.

7.5.2 Case Study Review for Land Required for Solar Retrofits

For existing medium and larger production sites and tank batteries, larger solar installations will be required to transition the sites to the proposed zero-emitting standard. As a case study, multiple sample sites throughout the country were evaluated to determine the space requirement for a solar installation that is equivalent to the energy of an instrument air system requiring 112 kilowatts (kW), which would be needed for large facilities not included in EPA's model plant analysis. Results are presented in Table 1.

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[77] 87 FR 73606

This case study highlights that the land requirement for many sites is likely to be between 0.6 – 1.5 acres. Several key considerations to consider when installing solar panels at existing well sites that hinder the compatibility include:

- Site area footprints have already been agreed to and installing large arrays will require revisiting existing agreements to modify, a time consuming and costly process. Many jurisdictions, including the BLM, prefer smaller facility footprints.
- Site layout is already optimized for existing infrastructure to fit within a facility area.
- Adding in solar infrastructure of panels, wiring, battery, etc. could lead to complications and unnecessary safety hazards as batteries are introduced near hydrocarbons.
- Snowfall is prevalent in many of these regions and will reduce efficiency of the optimally angled panels. Vertically oriented arrays to prevent snowfall interference may not be appropriate in all circumstances unreasonable given the climate, wind, and remote nature of these sites.

Table 1. Case Study – Physical Land Requirement for Solar Installations Replacing Power Supply for 112 kW Generator

Site Location	Optimally Angled Panels[a]					Vertically Angled Panels[b]				
	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage[g]
	kW	degrees	Hours			kW	degrees	Hours		
Carlsbad, New Mexico	620	28	5.1	2,067	0.7	1513	90	2.1	5,044	0.9
Midland, Texas	620	28	5.1	2,067	0.7	1558	90	2.0	5,193	0.9
Arnett, Oklahoma	735	30	4.3	2,452	0.8	1318	90	2.4	4,392	0.8
Denver, Colorado	719	31	4.4	2,396	0.8	1171	90	2.7	3,904	0.7
Pinedale, Wyoming	988	33	3.2	3,294	1.1	1091	90	2.9	3,635	0.6
Williston, North Dakota[h]	1318	35	2.4	4,392	1.5	1091	90	2.9	3,635	0.6

a. Optimally angled tilt (annual average) determined from National Renewable Energy Lab (NREL)'s PVWatts® Calculator; https://pvwatts.nrel.gov/pvwatts.php

b. Vertically angled systems were suggested by Clean Air Task Force at EPA-HQ-OAR-2021-0317-1451.

c. Size of installation determined from Omni calculator methodology required inputs of electricity consumption and solar hours per day to determine roof area of solar panels; https://www.omnicalculator.com/ecology/solar-panel

d. Using NREL's PVWatts calculator in conjunction with the Omni calculator, it was determined roof area was equal to ground area for simplification as, there was a <1% difference in annual kWH production.

e. Footprint Hero was used to determine the lowest monthly average daily peak sun-hours for each location for both panels at optimal angle and 90 degrees; https://footprinthero.com/peak-sun-hours-calculator

f. Number of panels based on average panel output of 300 watts and 15 square feet.

g. Acreage for vertically angled panels assumes panels would be stacked two panels high.

h. The high latitude of Williston, North Dakota has the lowest monthly average daily peak sun-hours when the solar array is optimally positioned. When vertically positioned the peak sun hours increases from 2.4 hours to 2.9 hours.

EPA should also consider the following in conjunction with results of this analysis:

- the cost of land acquisition;

- right-of-way and easement concerns/limitations;
- projection of further land-use change requirements for solar installations; and
- percent of further land use change required for solar installations on designated wetlands.

For existing locations without accessible grid power and where there is an ability to acquire additional land to use solar or natural gas generators, operators will not have the ability comply with the current proposal.

7.5.3 The incremental costs and benefits have not been adequately justified at existing locations.

Within the technical Support documentation, EPA does include a scenario for monitoring intermittent vent controllers. Based on EPA's own assumptions, this type of program can achieve 96.7% reductions in emissions (based on emission factors) for an overall site level control efficiency of 65% based on semi-annual OGI monitoring. Since many large facilities within the proposal will be required to conduct quarterly OGI, we anticipate this control efficiency to be even higher.

Furthermore, since all well sites, central production facilities and compressor stations will already be subject to fugitive emission monitoring at some frequency, the incremental cost to implement such a program for pneumatic controllers would be solely based on the additional recordkeeping and reporting that an operator would need to implement. The incremental costs and benefits associated with the zero-emitting provisions in comparison with this option to monitor controllers for proper functioning within a company's LDAR program, have not been adequately justified given the numerous technical infeasibility challenges communicated with implementing solar-powered electric controllers, spacing constraints at some existing facilities to install certain equipment, and other emission offsets that will stem from implementing other forms of power generation.

In EPA's analysis, the emission reductions from inspections of intermittent vents are based on emission rates assumed to be halfway between perfectly operating post-inspection controllers and the overall emission rate that includes both perfectly operating and malfunctioning controllers. This suggests that EPA has no data or understanding of how often intermittent bleed devices may not function properly, which is an important distinction given the expected costs of implementing these requirements at all locations as proposed under EG OOOOc.

7.6 EPA's cost-benefit analysis significantly underestimates the costs of implementing the proposed zero-emissions standard and overestimates the technical capabilities of solar and electric controllers.

In our January 31, 2022 comment letter, we provided detailed comments on the technical challenges that operators within U.S. are facing as they convert facilities to electricity, pilot solar powered instument air systems, and install natual gas-driven instrument air systems, which we incorporate again by reference.[78] As our members begin to plan, design and install zero-emitting penumatic controllers, it is clear that EPA has not adequately accounted for the costs of this proposal; especially with respct to retrofit of existing facilities. Total project costs, including equipment and labor, to retrofit a large gathering and boosting compressor station could exceed $1,000,000, which is substantially higher than EPA's projections.

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[78] Comments found in EPA-HQ-OAR-2021-0317-0808

Upon review of the supplemental techncial Support Document, we have found EPA's cost-benefit analysis to significantly underestimate the cost (especially for retrofit of existing facilities) and overstate the techncial feasibility of making these retrofits as summarized below:

- EPA applied an emission factor for low-bleed pneumatic controllers, with a factor that by definition would be a high-bleed pneumatic controller. EPA has justified this update within the model plant by aligning the model plant to the proposed changes to Subpart W which is 6.8 scf/h. This emission factor is nearly a five-fold increase to the continuous low-bleed device emission factor; is greater than the threshold that had been applied to determine whether a device should be categorized as low-bleed or high-bleed; and a device with this level of emissions would not be allowed pursuant to NSPS OOOO or NSPS OOOOa. In our review of the proposed changes to Subpart W, we have asked EPA to provide the details of how this factor was determined as there is little documentation supporting this change. Regardless, it is an inappropriate factor for applying to a low-bleed device for NSPS OOOOb and EG OOOOc because an operator would not be able to install a continuous bleed natural gas-driven pneumatic controller with this manufacturer rating as it is considered a high-bleed pneumatic controller.
- EPA continues to describe application of solar-powered and electric controllers as being directly powered by the grid or solar technology in the model plant analysis. Operator experience is that sufficient air is required to properly control the pneumatic controllers, where an instrument air system (i.e., an air compressor and associated equipment and piping) is required in nearly all applications. Electric controllers lack the speed and performance of gas-powered or air-powered actuators and there are limited equipment configurations where electric controllers are technically feasible. Specifically, electric controllers have inadequate duty cycle ratings, and the torque ratings are typically too low for reliable performance. This significantly limits the utility of electrically actuated controllers. Even if they performed comparably to gas-powered actuators, electrically actuated controllers have a higher failure rate, especially for throttle service where the actuator is constantly adjusting based on process conditions instead of at a set point. The modelled analysis for these scenarios incorrectly estimates the cost-effectiveness of the proposed requirements.
- Application of solar technologies as it pertains to gathering and boosting compressor stations have not been adequately reviewed in EPA's model plant analysis. The production sector model plants are geared toward small well sites with only 4, 8 and 20 controllers analyzed. Larger facilities, i.e., those with more than 20 pneumatic controllers, are still not adequately accounted for.
    - The assumptions made by EPA in the model plant analysis severely underestimate the air compressor horsepower and instrument air needs for sites with more than 20 controllers. These smaller scale cost metrics will not linearly scale up with larger facilities where a new instrument air header and piping may need run across the larger Gathering & Booster station site and additional pipe supports or extended pipe rack may be necessary. In our January 31, 2022 comment letter we provided information on facilities using instrument air systems to power over 100 controllers.
- In a case study published by NREL[79], solar panel capital costs for off-grid production well sites are 2.7 times the cost of grid-connected well sites. This does not align with EPA assumptions.
- EPA's model plant assumptions do not adequately address costs associated with retrofit of existing facilities. We note that installation also necessitates the facility be temporarily shut in/shut down to

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[79] https://www.nrel.gov/docs/fy20osti/76778.pdf

perform retrofits, which does not appear to be accounted for. Additional costs for retrofit at existing facilities that are missing from EPA's analysis include:

  - Additional Land Requirement for Solar Panel Installation including acquisition costs.
  - Site Preparation – For existing sites with tree lines, trimming may be required to maximize sun exposure. Additionally, for larger sites with more significant solar installations, foundation prep including concrete slabs was not considered.
  - Solar panel maintenance and cleaning particulate accumulation.
  - Permitting[80], Insurance and inclusion of battery boxes to house batteries in cold regions do not appear to be accounted for.
  - Retrofits often require the existing methane pipe headers to remain in place as a source of fuel gas for on-site equipment (compressors, fired heaters, combustors/TO's, flares, etc.) and a new parallel air header needs to be run to a to all instruments. This can add significant costs depending on the site layout, if there is available space in the existing pipe rack and facility, or if additional pipe supports are also needed.

- While EPA recounts and summarizes the significant number of comments criticizing solar-powered controllers (87 FR 74764), the primary underlying basis to EPA's economic and technical feasibility analysis pertaining to the conversion of existing, natural gas-powered pneumatic control systems to zero-emission systems (e.g., electric, solar-powered) is based on a single report: *Zero Emission Technologies for Pneumatic Controllers in the USA initially published in August 2016 and then updated in November 2021 by Carbon Limits (on behalf of the Clean Air Task Force).[81]* The report and EPA's application of report costs within the model plant analysis have a number of flaws as we have described herein and as follows:

  - The 2021 Carbon Limits report authors primarily gathered information through interviews with three technology providers and two oil and gas companies, both production-oriented companies with limited application of the technologies. The report is based on installation of solar-powered instrument air systems at only 22 onshore production sites located in Alberta, Canada, Wyoming, Utah, and Peru. This is an extremely small sample size for a technology to be deemed technically feasible and cost effective for all U.S.-based oil and natural gas operations. In response to our comments Clean Air Task Force states "Some of the interviewed technology providers have installed these systems in over 400 well-sites." Again, this is a rather small population when considering the number of facilities that will be applicable to these rules.

  - The Carbon Limits report focuses on reliability of solar power systems in colder climates, not areas with limited sun exposure. The Canadian provinces cited in the study, Alberta and British Columbia, experience very large amounts of sunshine, supporting the idea that solar power

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[80] https://www.solarpermitfees.org/SoCalPVFeeReport.pdf

[81] This basis was explicitly stated by EPA on page 46 of 173 to document Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS), 40 CFR Part 60, subpart OOOOc (EG) (October 2022). EPA states, "The EPA notes that the primary basis for the costs used for the November 2021 analysis was not the White Paper, but rather a 2016 report by Carbon Limits, a consulting company with longstanding experience in supporting efficiency measures in the petroleum industry.The analysis was updated to reflect the information in the 2022 Carbon Limits report."

generation works best in areas with more sun. The study does not support reliability of solar powered systems in areas of limited sun exposure like West Virginia.

- Identified calculation errors and assumptions in the model plant analysis:
    - The EPA cost analysis appears to contain a calculation error in determining the annualized project cost; while a solar panel lifespan of 10 years was stated, a value of 15 years was used in the annualization, resulting in a 30% annual cost difference. See tabs in Supplemental TSD Ch 3 Pneumatic Controllers.xlsx tabs *BSER T&S new, BSER T&S existing, BSER Production new, and BSER Production existing.*
    - The EPA capital cost analysis for electric compressor retrofit at existing transmission, storage, and production sites does not consider applications greater than 10 hp (highest compressor and associated equipment (e.g., dryers, wet air receivers) is capped at $32,000). Larger-sized systems should be evaluated.
    - For electric powered compressed air systems, EPA applied an annualization period of 15 years. If the compressor equipment life is updated to reflect the 2021 Carbon Limits Study provided value of 6 years, this option is not economically feasible. It is unclear why EPA deviated from the Carbon Limits study for this assumption and not others.
    - Carbon Limits updated certain assumptions in the 2021 report release. For some assumptions, EPA continues to retain costs from the 2016 study, without explanation.
    - The Carbon Limits report assumed a greenfield installation factor of 1.5 times major equipment costs without any adequate explanation. Member experience suggests this is closer to 3 to4 times equipment costs.
    - EPA continues to assume at least 1 high-bleed pneumatic controller is present at existing source model plants, when the data submitted to EPA pursuant to 40 CFR Part 98, Subpart W suggests this is an incorrect assumption given the low number of high-bleed controllers still being reported. See Attachment C in EPA-HQ-OAR-2021-0317-0808.
    - The EPA deflated costs provided in 2021 dollars to 2019 dollars. As inflation continues to be elevated, this is an unrealistic assumption and not reflective of actual, or anticipated costs. Costs continue to increase across the economy. A more appropriate assumption would be to assume 2021 dollars are equal to 2019 dollars.

7.7 Recordkeeping and Reporting

As more surface site locations electrify pneumatic controllers over time, confirmation of compliance would be easily obtained through any inspection of a site that was connected to grid power, using solar panels or other instrument air system. Based on review of the issued reporting form (EPA-HQ-OAR-2021-0317-1536_content), it appears EPA's intent was to streamline recordkeeping and reporting to only natural gas-driven controllers, which are the affected facility. However, the language proposed within NSPS OOOOb per §60.5420b(c)(6)(i) and EG OOOOc is unclear in this regard. EPA should not require recordkeeping or reporting on pneumatic controllers that are not natural gas-driven.

8.0 Natural Gas-Driven Pneumatic Pumps

8.1 The applicability date for pneumatic pumps under NSPS OOOOb should be the date of the Supplemental Proposal.

While we maintain that the applicability of NSPS OOOOb should apply based on the December 2022 Supplemental Proposal, which included regulatory text for all affected facilities, this is particularly true for natural gas-driven pneumatic pumps. In the preamble (87 FR 74770)[82], EPA even acknowledges the proposed rule varies significantly from what was described in the November 2021 description for pneumatic pumps:

> ***The proposed NSPS OOOOb requirements in this Supplemental Proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition.*** *As noted above, in the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven pneumatic pump. In this Supplemental Proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site.*
>
> *…Specifically, the EPA is proposing that pneumatic pumps not driven by natural gas be used.* ***This is a significant change from the November 2021 proposal,*** *which would have required that emissions from pneumatic pump affected facilities be routed to control or to a process, but only if an existing control or process was on site****. (emphasis added)***

In these statements EPA acknowledges that not only did the affected facility definition expand to the collection of pumps at a site, but it also expanded to include piston pumps, which have not historically been regulated in NSPS OOOOa. Additionally, the proposed control options under NSPS OOOOb are completely unexpected and the hierarchy of options proposed would not have been a logical expectation based on the description in November 2021 proposal description. Specifically, operators have had no way of knowing:

1) Piston pumps would be affected facilities under §60.5365b(h).

2) The collection of both piston pump and diaphragm pumps would constitute an affected facility under §60.5365b(h).

3) The control standard would require a zero emissions control or a suite of ongoing certifications to demonstrate feasibility or infeasibility in §60.5393b.

4) Modification and reconstruction have never applied to such small ancillary equipment such as a single piston pump or diaphragm pump.

Therefore, the applicability date for pneumatic pumps under NSPS OOOOb should be the date of Supplemental Proposal.

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[82] Federal Register / Vol. 87, No. 233 / Tuesday, December 6, 2022 / Proposed Rules

8.2 Under NSPS OOOOb, we support the use of non-emitting pneumatic pumps for newly constructed well sites, tank batteries, and compressor stations, but we do not support the hierarchy of options proposed and inclusion of additional certification statements. The standard should be technology neutral similar to the pnuematic controller requirements.

The control options proposed for natural gas-driven pneumatic pumps are the same as those proposed to control natural gas-driven pneumatic controllers, yet the EPA is requiring additional technical demonstrations for pneumatic pumps that are not required for pneumatic controllers. We believe the requirements for natural gas-driven pneumatic pumps should be similar to those proposed for pneumatic controllers and the allowance for routing emissions to a control device which is allowed for pumps be extended to controllers (without any additional technical demonstration).

Furthermore, the hierarchal structure as proposed does not make logical sense as routing emissions to process, which has been a long-standing compliance option under the NSPS, is placed at a lower tier than that of implementing instrument air systems using solar or natural gas. As provided in Comment 12.9, the additional certifications associated with this hierarchy should be removed. The CAA already has provisions for knowing criminal violations related to false statements, which includes reference to false material statement, representation, or certification in/omits material information from/alters, conceals or fails to file or maintain a document filed or required to be maintained under the CAA.

8.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic pumps.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms ‘natural gas-driven pneumatic pump’ and ‘pneumatic pump’ interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic pumps. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric pumps as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(h)(1):

> *For the purposes of §60.5393b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic pumps at a site is increased by one or more.*

We offer the following suggested for modification redline to §60.5365b(h)(2):

> *For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic pumps in accordance with paragraph (h)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven pneumatic pumps at the site in accordance with paragraph (h)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (h)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (h)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic pumps is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of natural gas-driven pneumatic pumps”*

criterion in (h)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of natural gas-driven pneumatic pumps replaced exceeds 50 percent. For purposes of paragraphs (h)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of ~~component~~ natural gas-driven pneumatic pump replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic pump replacement.

(i) If the owner or operator applies the definition of reconstruction in §60.15, reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic pumps exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic pumps at the site. The "fixed capital cost of the new pneumatic pumps" includes the fixed capital cost of all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic pumps replaced, reconstruction occurs when greater than 50 percent of the pneumatic pumps at a site are replaced. The percentage includes all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]. If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic pumps that are replaced, the owner or operator must comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review also apply.

8.3.1 Additional clarifications are required for the proposed requirements for reconstruction of pneumatic pumps.

In review of the proposed regulatory text provided for §60.5365b(h)(2), the following elements of the proposed regulatory text require clarification:

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed.** Similar to natural gas-driven pneumatic controllers, the proposed language in §60.5365b(d)(2)(ii) suggests that reconstructed natural gas-driven pneumatic pumps would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic pumps. We believe it was EPA's intent to not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 proposal.

8.4 Suggested clarifications to certain proposed definitions related to pneumatic pumps in NSPS OOOOb and EG OOOOc.

While EPA expanded the applicability to include piston pumps, EPA did not include a definition for what a piston pump is or is not beyond the definition for natural gas diaphragm pump currently provided. Without this additional definition we request the following technical clarification as it applies to lean glycol circulation pumps. We do not believe it was EPA's intent to include these within the new zero-emitting provisions and historically EPA made it clear that this was not their intent to include these under NSPS OOOOa.

> ***Natural gas-driven diaphragm pump*** *means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a ~~diaphragm~~ pneumatic pump.*

8.5 The provisions included §60.5365b(h)(3) should also reference piston pumps.

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. We support EPA's retention of the provisions proposed in §60.5365b(h)(3) as these pumps will, by their very nature, result in very low and intermittent emissions. In the model plant analysis, the emissions for a single natural gas-driven piston pump is only 0.11 tpy VOC and 0.38 tpy methane. Temporarily used piston pumps would emit even less, which is why they have historically been exempt from the control standards. Such an exemption would be analogous to what also already been granted for temporary natural gas-driven diaphragm pneumatic pumps, and we believe it was EPA's intent to also include piston pumps in this provision.

We offer the following suggested redline to §60.5365b(h)(3):

> *A single natural gas-driven diaphragm pump or piston pump that is in operation less than 90 days per calendar year is not part of an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year in accordance with §60.5420b(c)(15)(i) and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.*

8.6 Natural gas-driven pneumatic pumps in compliance with NSPS OOOOa

NSPS OOOOa requires certain diaphragm natural gas driven pumps to be routed to a control device or process. As such, these pumps are already controlled by at least 95%. EPA has not adequately considered or accounted for how to handle these existing controlled pneumatic pumps within the proposed rules. Specifically, these pumps should meet the requirements of EG OOOOc by continuing to comply with NSPS OOOOa. These pumps should also be excluded from modification and reconstruction under NSPS OOOOa.

8.7 EPA's Model Plant Analysis for Conversion to Electric, Solar or Instrument Air Pumps

EPA assumptions for converting pneumatic pumps to zero-emitting has a distinctly separate set of cost assumptions from the pneumatic controllers even though the same technologies are being proposed for use. While EPA relied on costs from the 2016 and 2021 Carbon Limits report for pneumatic controllers, EPA uses different costs and assumptions as it pertains to converting to electric (assumed to be grid power) and solar pumps, which are not well documented and appear based on old information dating back to 2012. The EPA's economic feasibility analysis for pneumatic pumps presented in file "Supplemental TSD Ch 4 Pneumatic Pump.xlsx" are also only adjusted to 2019 USD from 2012 dollars. Thus, values presented are underestimated by at least 14%.[83]

9.0 Well Liquids Unloading Operations

As we communicated to EPA in our January 31, 2022 letter[84], well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective because there are numerous misconceptions about why and how this activity is conducted. While we support EPA's inclusion of well liquid unloading operations as an affected facility, the regulation should be based solely on the work practice standard outlined in §60.5376b(c)(2) and (d) and should not include a zero-emission limit as provided in §60.5376b(b). To this end, the recordkeeping and reporting requirements must be amended to be a workable framework for operators to assure compliance including removal of the certification statement by an engineer in every instance that venting may occur.

Lastly, the applicability for liquid unloading operations must be designated as the date of the Supplemental Proposal as the recordkeeping requirements were not explicitly known for each event that ocurred prior to the publication. Much of the recordkeeping elements proposed in the December 2022 proposal, including the certification statement by engineer, was not anticipated based on the descriptions in the November 2021 proposal.

9.1 Well liquid unloading operations should be subject to work practice standards and not held to a zero-emission limit.

API supports the proposed alternative measures outlined in §60.5376b(c)(2) and (d), which provide a clear and rational work practice standard based on Best Management Practices (BMPs) that achieve the intent to reduce

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[83] https://www.usinflationcalculator.com/

[84] EPA-HQ-OAR-2021-0317-0808

emissions from liquid unloading of gas wells. These provisions should be considered BSER and should not be considered an exception to the standard as currently proposed in §60.5376b(c).

We appreciate EPA's recognition that solely imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations that in many situations could severely halt natural gas production. For some situations, a certain unloading technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. The work practice standards proposed in §60.5376b(d) allow operators the flexibility needed to minimize emissions from well liquid unloading, while allowing for unexpected situations or outcomes that may occur during the unloading operation that might result in a minimal amount of emissions to be vented.

To be clear, while we support the work practice provisions in §60.5376b(c)(2) and (d), we do not support the provisions proposed in §60.5376b(b) establishing a zero-emission limit on liquid unloading operations as this limit creates undue burden of compliance when EPA has acknowledged it is known that not every liquid unloading operation can technically or safely meet the zero-emission limit. This undue burden is compounded when considering the logistical and practical implementation of the associated recordkeeping, reporting and certification statements also proposed. See also Comment 12.9.

9.2 Additional clarification to the proposed definition of liquids unloading is warranted.

As we previously commented in our January 31, 2022 letter, other well maintenance and workover activities may occur on a well that are distinctly different, require separate specialized equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. EPA must explicitly provide clarification to address these distinctions, within the definition for "liquids unloading" so not to confuse other activities that might occur at a well with the liquids unloading operation provisions as proposed.

Our suggested clarification to the definition of liquids unloading under §60.5430b and §60.5430c is as follows:

> *Liquids unloading means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production. Routine well maintenance activities, including workovers, screenouts, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.*

9.3 The recordkeeping and reporting for liquids unloading operations must be simplified into a manageable framework for operators and streamlined for liquid unloading operations that vent to atmosphere.

The information proposed by EPA within §60.5420b and §60.5420c for the recordkeeping and reporting as it pertains to liquid unloading operations is focused on an operator tracking and certifying techniques and less focused on allowing an operator to perform the necessary procedures to unload liquids accumulated within the wellbore and maintain natural gas production with as minimal emissions as possible. To address this shortfall, we suggest EPA define the data operators should track per unloading operation and remove all superfluous records that generate additional burden for the operator and EPA without added environmental benefit. These suggestions assume that liquid unloading operations are to be conducted using a work practice standard according to our suggestion in Comment 9.1.

The current proposed recordkeeping requirements do not offer a reasonable framework for operators to maintain compliance assurance. In fact, EPA has included a certification by professional engineer for every instance a well unloading operation vents emissions to atmosphere in §60.5420b(c)(2)(ii)(B) and §60.5420b(b)(3)(ii)(B) based on the proposed zero emissions limit standard. This may not be known to an operator until the liquid operation is taking place based on a variety of parameters. For context, a single well affected facility may undergo multiple liquid unloading operations in a single compliance period. For example, one well may necessitate an unloading schedule of four times in a year. Based on best management procedures, three (3) of these events may occur with zero emissions, while one (1) of the events might vent to atmosphere for a short duration using the same technique. The justification provisions in §60.5420b(c)(2)(ii)(B) are untenable when the same technique used on a well may resulted in zero emissions during some liquid operations, but not during all liquid unloading operations in the same compliance period. The fact is that in some instances a well liquid unloading operation may need to vent emissions for short duration, sometimes a little as 30 minutes, to safely perform the liquid unloading operation. We therefore request:

1) EPA remove the additional engineering certification statements under the guise of technical demonstrations. These additional certifications would be unnecessary if the standard followed a work practice procedure (see Comment 9.1).

2) Limit recordkeeping and reporting to liquid unloading operations that result in emissions only. This would reduce the administrative burden for thousands of liquid unloading operation events. This is also consistent with how both Colorado and New Mexico have organized recordkeeping and reporting for their state regulations.

   Our suggestions to streamline and simplify the recordkeeping and reporting for liquid unloading operations is as follows:

> *For each gas well affected facility that conducts liquids unloading operations during the reporting period that resulted in emissions vented to the atmosphere:*
>
> - *US Well ID*
> - *The number of liquids unloading events during the year that resulted in emissions.*
> - *The date and time of each liquid unloading operation where venting occurred.*
> - *The duration of venting in hours.*
> - *Reason venting occurred*

Additional recordkeeping for liquid unloading operations should include:

> *Documentation of your best management practice plan developed under paragraph §60.5376b(d). You may update your best management practice plan to include additional steps which meet the criteria in §60.5376b(d).*

10.0 Compressors

API endorses the comments being submitted by GPA Midstream Association as it pertains to reciprocating and centrifugal compressors and provides the following additional comments.

10.1 Reciprocating and Centrifugal Compressors should be subject to a work practice standards with clear repair and delay of repair provisons instead of an emission standard.

Within Section IV.I.of the preamble (87 FR 74796), the EPA acknowledges *"over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder."* EPA also provides its rationale for the proposed level of excessive leaking (87 FR 747996) as "*the 2 scfm flow rate threshold was established based on manufacturer guidelines indicating that a flow rate of 2 scfm or greater was considered indicative of rod packing failure."* In summary, the EPA anticipates emissions from rod packings over time even from reciprocating compressors that are properly operated and maintained.

Yet, at the same time, EPA proposes to establish the 2 scfm flowrate as a not-to-exceed standard of performance, such that a violation occurs if flow rate exceeds that value (87 FR 74797). In doing so, EPA fundamentally misconstrues the manufacturers recommendations. In practice, exceeding a manufacturer-recommended flow rate is an indication that a repair should be made. Exceeding that rate does not necessarily compromise operability of the unit and, in fact, the values are selected to allow continued operation for the period necessary to arrange for needed repairs to be made. EPA without explanation proposes to transform what in practice constitutes an action level into a regulatory cap that cannot be exceeded without the prospect of incurring a violation. EPA's proposal is at odds with the facts and is an unreasonable reinterpretation of standard maintenance practices.

Therefore, if EPA is intent on setting a numeric standard of performance, the value must be well above the 2 scfm that EPA believes to be the standard manufacturer recommendations. The value must accommodate operations for a reasonable and potentially significant period of time that may be needed to accomplish needed repairs. If EPA takes this path, a reproposal is necessary so that we can know the newly proposed value, understand EPA's rationale, and have an opportunity to submit comments on the record. Alternatively, we believe that the flowrate can be established as a work practice that would trigger a repair obligation rather than constitute a numeric emissions limitation. While it is true that flow can be measured here, it is not technically or economically practicable to install measurement systems that would assure complliance with a numeric emissions limitation. See CAA § 111(h)(2)(B).

10.2 Clarification is required for compressors with multiple cylinders or seals.

In the November 2021 preamble (86 FR 63216), EPA described the rod packing requirements as follows:

> *"We are proposing that BSER is to replace the rod packing when, based on annual flow rate measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. We are proposing that if annual flow rate monitoring indicates a flow rate for any individual cylinder as exceeding 2 scfm, an owner or operator would be required to replace the rod packing."*

In looking at documentation for the dry seal proposed requirements, the Natural Gas Star[85] report where this value was seemingly derived, it is stated, “*During normal operation, dry seals leak at a rate of 0.5 to 3 scfm across each seal (1-6 scfm for a two seal system), depending on the size of the seal and operating pressure…. An example of one type of tandem seal with leak rates ranging between 0.5 to 3 scfm for 1.5 to 10 inch compressor shafts, for compressors operating at 580 to 1,300 psig pressure.*”

In the proposed text provided in §60.5380b or §60.5385b(a), the distinction that the limits are per cylinder or seal is unclear. It would be impratcical for a compressor with multiple cyclinders (reciprocating) or seals (centrifugal) to operate the same as compressor with only a single cyclinder or seal. As the Natural Gas star report documents, it is also impractical to expect the same level of emissions from dry seals for various sized units.

Therefore, EPA must clarify that the emission threshold designated is by cylinder or throw (reciprocating) and per seal (centrifugal). We note that the following suggested redlines for NSPS OOOOb and EG OOOOc are consistent with §95668 (c)(4)(D) of the 2017 California’s GHG Emissions Regulations, which this proposed standard was based:

> *§60.5385b(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5393c(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5380b(a)(4)(i): The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section.*
>
> *§60.5392c(a)(1): You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. The volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm.*

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[85] https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/ll_wetseals.pdf

10.3 Conducting annual measurements on temporary compressors is logistically impractical and temporary compressors should be exempt from §60.5365b(b) and (c)(b).

Temporary compressors should be exempt from the monitoring requirments as it would be infeasible to conduct monitoring on a compresor that will be removed from a site after less than a year. Equipment that is intended for temporary use and is not a stantionary source should not not be subject to either NSPS OOOOb and EG OOOOc. API requests EPA make the following clarifications to address this concern:

> *§60.5365b(b): Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart. A centrifugal compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*
>
> *§60.5365b(c): Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart. A reciprocating compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*

10.4 Reciprocating Compressors

While API supports certain aspects of the Supplemental Proposal for reciprocating compressors, addiitonal clarifications must be made. The following amendments, in addition to the items outlined above and in comments submitted by GPA Midstream Association, would alleviate some of the significant technical cocnerns our members have with the proposed requirements.

- **Emissions from reciprocating rod packing vents that are routed to a process or flare should be considered an adequate alternative in reducing emissions.** EPA should continue to allow an option for rod packing vents to be routed to a control device for new, modified and existing facilities. The incremental benefit achieved between monitoring and subsequent repair (if applicable) versus capturing the vent to control device that achieves 95% destruction efficiency has not been substantiated by EPA within their cost benefit analysis. This is especially true for any compressor that already is designed and configured to route rod packing to a flare or other combustion device.

- **EPA should provide additional flexibility for addressing rod packing leaks by allowing operators to forgo annual emission measurements and replace rod packing annually.** Given the sheer number of compressors that will apply to NSPS OOOOb and EG OOOOc, EPA should provide flexibility by allowing operators the option to change out rod packing annually or 8760 hours (whichever comes first), which is similar in approach but more frequent than the current requirements in NSPS OOOO and OOOOa, or to perform the newly proposed annual monitoring and replacement of rod packing if emissions exceed to specific threshold as identified.

- **Repair parameters were omitted from the proposed regulatory text.** The EPA states their intent to define some repair parameters for reciprocating compressors in the preamble (87 FR 74798):

> *"The proposed NSPS OOOOb regulatory text also specifies that flow rate monitoring be conducted in operating or standby pressurized mode, and "repair" and "delay of repair" schedules, in addition to other clarifying requirements. The EPA is proposing to require conducting flow rate measurements during operating or standby pressurized mode because the measured emissions would be representative of actual emissions during operations. Repair schedules are proposed to require repair of equipment in a timely manner to mitigate emissions. Delay of repair would be allowed when owners and operators required more time to repair equipment based on scenarios beyond the owner or operator's control (e.g., issues with availability of equipment or where repair necessitates a compressor shutdown when redundancy of compressors is not available)."*

However, the repair and delay of repair schedules could not be located in the proposed regulatory text. As stated in Comment 10.1, the EPA should establish a monitoring schedule for reciprocating compressors with reasonable repair times. Further, allowances should be incorporated to address situations that delay repairs, appropriately.

California regulations governing rod packing emissions, upon which these proposed regulations are based, require repair within 30 calendar days from the date of the initial emission flow rate measurement. Furthermore, repair of a compressor typically cannot be performed while the compressor is in service, and some situations may arise that warrant delay of repair. We therefore request EPA amend the provisions in §60.5380b and §60.5385b to accommodate a work practice standard that includes clear provisions for repair or replacement and delay of repair or replacement that is consistent with §60.5397b(h)(3).

10.5 Centrifigal Compressors

10.5.1 Clarification is requested to the definition of centrifugal compressor.

Within the definition "centrifugal compressor" in §60.5430b and §60.5430c, EPA describes the compressor as "*discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers."* The phrasing of "significantly higher-pressure" should be further delineated to eliminate ambiguity. If left undefined the regulated operator does not have a clear understanding of what is affected and what is not affected.

The definition of centrifugal compressor as it was used in the initial NSPS OOOO rulemaking only affected wet-seal centrifugal compressors, which includes a relatively small population of affected facilities that were generally considered to discharge significantly higher-pressure natural gas. With the expansion of the NSPS OOOOb and EG OOOOc to also include dry seal compressors, which are more widely utilized, additional clarity is warranted.

In the oil and natural gas industry, compressors that boost natural gas pressures are normally designed to discharge natural gas greater than 300 pounds per square inch differential (psid). The original intent of EPA including this language was to exclude smaller compressors with low differential pressure (e.g., process compressors, vapor recovery units, and other low pressure service units). With this consideration, API recommends that EPA update §60.5430b to include a definition of significantly higher-pressure and includes the following language:

> *Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart. For the purposes of §60.5380b, significantly higher-pressure means having a design pressure differential greater than 300 pounds per square inch differential (psid).*

10.5.2 The emission limit for dry seal compressors should properly account for compressor size.

The origin of and basis for the proposed three (3) scfm limit for dry seal compressors is not provided within the EPA docket and associated references. API suspects that the genesis of this number did not consider variable compressor sizes, resulting in a low value for the standard that is not representative of all operations. In Section IV.G.1.b.iii of the Federal Register, the origin of this value is as follows: *"The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in §95668(d)(4-9), California's Regulations*[86] *for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate*[87]*."* Research into the underlying sources of the CARB regulation does not yield supporting information for the development of the 3 scfm standard. EPA should supplement the docket with information to support why this value is representative of the population of dry seal compressors across the nation (taking into consideration compressor size variability).

Larger compressors usually have larger shaft diameters, higher operating speeds, and greater operating pressures. These three variables all contribute factors to the amount of gas that might ultimately slip through the seals. The combination of these three factors will usually yield higher leak rates from seals as measured on a volumetric basis, thus larger compressors will have a higher baseline for normal operations.

Based on data submitted to the EPA pursuant to 40 CFR Part 98, Subpart W for the 2021 calendar year, dry seal compressor driver power output ranged between 5 – 42,000 horsepower and for wet seals the compressor driver power output ranged between 40 – 53,665 horsepower.[88] We do not believe compressors associated with the higher end of this range should be expected to operate the same as compressors closer to the lower end of this range. Table 2provides more details on our short analysis showing variable sizes of both dry and wet seal compressors as reference.

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[86] https://ww2.arb.ca.gov/sites/default/files/2020-03/2017 Final Reg Orders GHG Emission Standards.pdf

[87] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf, page 100.

[88] Information was extracted from EPA's Envirofacts database using the GHG query builder: https://enviro.epa.gov/query-builder/ghg.

Table 2. Variation in Compressor Driver Output as Reported under EPA's Greenhouse Gas Reporting Program for Calendar Year 2021

Compressor Horsepower Driver Details as reported to EPA for Calendar Year 2021	Count of Compressors in Dataset	Compressor driver power output (Horsepower)		
		Average	Minimum	Maximum
Dry Seals				
Onshore natural gas processing	310	6,427	5	38,000
Onshore natural gas transmission compression	812	14,431	144	42,000
Underground natural gas storage	19	9,817	5,700	15,280
Wet Seals				
Onshore natural gas processing	199	9,426	40	53,665
Onshore natural gas transmission compression	345	5,027	990	30,000
Underground natural gas storage	22	3,910	1,275	9,800

10.5.3 Additional clarification is needed regarding the volumetric flow.

Both wet seal and dry seal systems often use an inert gas, such as nitrogen, for system blankets at positive pressure. That nitrogen vents through the same vent as the seal gas. So measured total vent rates may be overestimating the amount of methane or VOC being vented to atmosphere. Actual vent rates of methane and VOC could be under the standard, but the total volumetric flow could be over due to the nitrogen blanket. EPA should make clear that the standard could be interpreted as either total volumetric flow or methane and VOC flow depending on which method of monitoring is employed.

EPA should also expand the volumetric flow measurement options to allow for alternative ways to obtain the methane and VOC flow:

- Use of thermal mass meter or ultrasonic meter readings in conjunction with gas composition samples to calculate methane and VOC flow, or
- Flow balance equations (i.e., if the amount of inert gas into the system is metered, then that volume could be subtracted from the total flow measurement, thus yielding the methane and VOC only flow.)

10.5.4 The wet seal centrifugal compressor requirements must be clarified between NSPS OOOOb and EG OOOOc.

It is unclear why the standards between NSPS OOOOb and EG OOOOc for centrifugal compressor standards are different:

- NSPS OOOOb – Dry seal compressors and "self-contained wet seal compressors" can only comply with volumetric standard. All other wet seal compressors can only comply with the 95% capture and control requirement.
- EG OOOOc – Any wet seal compressor can either comply with volumetric standard or reduce emissions by 95% through a control standard.

The implications of the NSPS OOOOb regulations seem to be that the 3 scfm volumetric standard is equivalent to the 95% capture and control requirement. If this is the case, then it stands to reason that all centrifugal

compressors should be able to choose to comply with either the volumetric standard or the 95% capture and control practice.

If owners of centrifugal compressors had the option to comply with either standard, it obviates the need for a specially defined class of compressors: "Self-contained wet seal compressors." Removing this definition from the rule would result in a more simple and straightforward understanding of the rule requirements. API proposes the NSPS OOOOb standards mimic the EG OOOOc standards.

10.5.5 The proposed requirements for Wet Seal Centrifugal Compressors do not consider our previous comments regarding the unique equipment design in the Alaskan North Slope.

On the Alaska North Slope (ANS) there is not a market for natural gas sales. Most of the gas that is produced with the oil is separated and either used as a fuel or is compressed (using large wet seal compressors) to be reinjected back down hole for gas lift or enhanced oil recovery. The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.

Wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures most of the gas by volume then routes that gas to a flare, as described in our January 31, 2022 comment letter[89]. The ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum / tank, where any remaining entrained gas breaks out and is vented to atmosphere. In 2010, EPA's Natural Gas Star[90,91] program, in conjunction with BP, conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis concluded that the sour seal oil degassing design employed on the ANS has greater than 99% emission control by volume. This same study is also cited by the CARB regulations references. It would stand to reason that this system of gas capture and control should be allowable to use the volumetric standard.

In summary, wet seal compressors with the sour seal oil traps in Alaska as described above, route the gas to the flare, not to the "compressor suction." Because of this, these compressors would seemingly not meet the definition of "self-contained wet seal compressor." However, there is language in that definition which suggests that the purpose of that definition is that degassed emissions do not route to atmosphere as proposed in §60.5430b and §60.5430c (***emphasis added***). Therefore, API offers the following redline for the definition of self-contained wet seal centrifugal compressor:

> *Self-contained wet seal centrifugal compressor means a wet seal centrifugal compressor system which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to either another process or combustion device ~~that is a closed process that ports the degassing emissions to the natural gas line at the compressor suction~~ (**i.e., degassed emissions are recovered**). The de-gas emissions are routed back to ~~suction~~ a process or combustion device directly from the intermediate closed degassing process ~~degassing/sparging chambers~~; after the intermediate closed process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.*

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[89] EPA-HQ-OAR-2021-0317-0808

[90] https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf

[91] https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf

Alternatively, as outlined in Comment 10.5.4, EPA could allow all centrifugal compressors the option to comply with the volumetric standard thereby obviating the need for a special definition for a “self-contained wet seal compressor.”

11.0 Leak Detection and Repair at Gas Processing Plants

API supports EPA’s proposal for bimonthly OGI monitoring for equipment leaks at gas processing plants. We also support incorporation of NSPS Vva into NSPS OOOOb and EG OOOOc as an alternative monitoring option with the additional simplifications EPA has proposed. While API also generally supports the use of Appendix K for OGI monitoring at gas processing plants, we have several comments with respect to proposed Appendix K as provided in Attachment A, which are in direct response to EPA’s solicitations within the preamble.

In addition to the above items, API offers the following comments concerning leak detection and repair requirements at gas processing plants.

11.1 Closed vent systems should be monitored annually using OGI or Method 21.

EPA is proposing initial and bi-monthly OGI or quarterly Method 21 monitoring of closed vent systems which are increased monitoring frequencies when compared with the existing annual Method 21 monitoring under NSPS OOOO, NSPS OOOOa, NSPS Vva, and other LDAR regulations. API’s previous comments on this topic[92] were intended to voice support for the use of OGI in monitoring closed vent systems and did not fully consider the implications and minimal environmental benefits of more frequent monitoring.

Closed vent systems have historically been subject only to initial and annual inspections due to their low leak rates. Closed vent systems rarely leak because of the small number of components and lack of constantly moving parts. The hard piping or ductwork in closed vent system do not experience the same wear and tear and potential for leaks as moving parts that generate friction. While OGI does not have the same proximity challenges as Method 21, more frequent monitoring of closed vent systems would still be impractical for both methods as parts of closed vent systems are considered difficult to monitor. More frequent inspections for closed vent systems at gas plants under NSPS OOOOb and EG OOOOc would also be more stringent than the requirements for refineries and chemical plants. Therefore, API recommends that for closed vent systems, hard piping be subject to an initial Method 21 or OGI inspection and annual AVO inspections and ductwork be subject to an initial Method 21 or OGI inspection and annual Method 21 or OGI inspections. If EPA decides to finalize the increased monitoring frequency for closed vent systems, they must provide additional justification including the additional environmental benefits expected from more frequent monitoring of equipment that rarely leak.

Emissions detected from closed vent systems do not constitute a violation of the “no identifiable emissions” standard provided work practice standards are fully implemented. See Comment 5.1 for a more detailed discussion.

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[92] EPA-HQ-OAR-2021-0317-0808

11.2 The lack of a VOC or methane concentration threshold expands monitoring requirements with minimal, if any, environmental benefit.

As API noted in its prior comments[93], EPA should retain the current 10 percent by weight threshold for VOC and propose a similar concentration threshold for methane, which we suggested as 1 percent by weight threshold for methane. In the Supplemental Proposal, EPA is proposing that monitoring apply to each piece of equipment “that has the potential to emit methane or VOC”, which is effectively a zero-applicability threshold for both methane and VOC.

Some streams at gas processing plants contain methane or VOC but in such low concentrations that monitoring would be meaningless as it would likely always result in no detected emissions. Examples of such streams include but are not limited to purity ethane, acid gas, ancillary chemicals, wastewater, and recycled water. The proposed monitoring of additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with minimal, if any, environmental benefit.

In its existing LDAR regulations, EPA has recognized and reaffirmed the need for concentration thresholds to achieve cost-effective emission reductions. The agency has not provided sufficient justification for deviating from this longstanding practice with this rulemaking. Based on an initial review of EPA’s TSD[94] from the November 2021 Proposal, API notes the following about EPA’s analysis:

- EPA considers only components in VOC service and non-VOC service, which the agency appears to define as follows:

> *“In VOC service” is defined as a component containing or in contact with a process fluid that is at least 10 percent VOC by weight or a component “in wet gas service”, which is a component containing or in contact with field gas before extraction. “In non-VOC service” is defined as a component in methane service (at least 10% methane) that is not also in VOC service.*

- EPA estimates VOC and methane emissions and therefore emission reductions and cost-effectiveness using only the following composition ratios identified in Table 10-8 of the TSD:

Component Service	Methane: TOC	VOC: TOC
VOC Service	0.695	0.1930
Non-VOC Service	0.908	0.0251

- EPA appears to treat the “potential to emit to methane” as equivalent to “in non-VOC service” in evaluating control options:

> *In addition to selecting one of the LDAR programs above, the EPA considered which components would be subject to the LDAR program. The current NSPS applies to components in VOC service (Option A). The EPA considered expanding the applicability to include components that have a potential to emit methane, which would add the components classified in this document as non-VOC service components (Option B).*

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[93] EPA-HQ-OAR-2021-0317-0808

[94] EPA-HQ-OAR-2021-0317-0166

Therefore, EPA does not appear to fully consider the cost-effectiveness of a potential to emit applicability threshold. API reiterates that EPA should retain the current 10 percent by weight threshold for VOC and establish a similar concentration threshold for methane (suggested as 1 percent by weight). Refer also to Attachment A.

In Comment 11.3, API offers recommended redlines to address this concern. Regarding how to determine when a piece of equipment is not subject to monitoring, the language in §60.5400b(a)(2) should also be revised as appropriate.

11.3 EPA should clarify which equipment is included in the evaluation of capital expenditure.

The definition of equipment is unclear on which equipment is considered when evaluating whether a capital expenditure occurred because capital expenditure is a definition, not a standard or requirement. This lack of clarity could lead to varying interpretations and uncertainty on whether a capital expenditure occurred. For other regulations, EPA has clarified the scope of equipment considered for the affected facility[95]. For leak detection and repair, an appropriate scope would be to apply the same definition of equipment to the capital expenditure evaluation as the standards and requirements. Therefore, the definition of equipment should clearly specify it also applies to capital expenditure.

To address this and the previous comment, API offers the following recommended redlines to definitions in §60.5430b.

> *Equipment, as used in the standards and requirements and for purposes of evaluating capital expenditure in section 60.5365b(f)(1) of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector ~~that has the potential to emit~~ in methane or VOC service and any device or system required by those same standards and requirements of this subpart.*
>
> *In methane service means that the piece of equipment contains or contacts a process fluid that is at least 1 percent methane by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in methane service.)*
>
> *In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in VOC service.)*

12.0 Overarching Legal Issues

12.1 The new source trigger date should be December 6, 2022, the date the Supplemental Proposal was published in the Federal Register.

In a memorandum associated with the Supplemental Proposal, EPA "solicits comments on whether CAA § 111(a) provides EPA discretion to define 'new sources' based on the publication date of the Supplemental Proposal and,

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[95] U.S. EPA Applicability Determination Index Control Number: 0600027, Modification and Capital Expenditure Calculations, dated February 9, 2001.

if so, whether there are any unique circumstances here that would warrant exercising of such discretion in this rulemaking by the EPA."

API believes that not only does CAA § 111(a) allow EPA to define the new source trigger date based on the publication date of the Supplemental Proposal, but also in fact requires it. Further, as API provides below, there are significant circumstances here that would warrant EPA altering the new source trigger date to December 6, 2022.

As explained in our January 31, 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) on the original NSPS OOOOb and EG OOOOc proposed rule, the original proposal was fundamentally incomplete because no proposed regulatory text was published or otherwise made available at the time of proposal. As a result, that proposal could not serve to set the new source trigger date for new requirements described in the proposed rule.

In the Supplemental Proposal, EPA reasserted that, except for newly proposed standards in the Supplemental Proposal (such as the standards for dry seal centrifugal compressors), the new source trigger date will be the date the original proposal was published in the Federal Register. EPA explains that "CAA Section 307(d)(3) specifies the information that a proposed rule under the CAA must contain, such as a statement of basis, supporting data, and major legal and policy considerations; the list of required information does not include proposed regulatory text." (87 Federal Register (FR) R 74716).

EPA further explains that "the Administrative Procedures Act (APA), which governs most Federal rulemaking, does not require publication of the proposed regulatory text in the Federal Register" and instead specifies that "notice of proposed rulemaking shall include ''*either* the terms or substance of the proposed rule *or* a description of the subjects and issues involved.'' (Emphasis added)." *Id*. EPA concludes that "the APA clearly provides flexibility to describe the ''subjects and issues involved'' as an alternative to inclusion of the ''terms or substance'' of the proposed rule." *Id*.

As an initial matter, EPA's analysis on this point indicates that EPA believes the CAA and the APA provide the flexibility to select November 15, 2021 as the trigger date for new sources, but nothing in EPA's analysis specifically concludes or determines that it must use the November 15, 2021 date. API believes that EPA's rationale for using November 15, 2021 remains flawed for three reasons. The lack of regulatory text (which was neither in the Federal Register notice nor otherwise made available in the docket prior to the close of the comment period) prevents the original proposal from setting the new source trigger date.

First, the CAA § 111(a)(2) definition of "new source" uses the term "proposed *regulations*" in defining the new source trigger date. As we explained in our comments on the original proposal, a preamble unaccompanied by regulatory text is not a "regulation." Here, the preamble to the original proposal was simply a description of the proposed regulations, but by itself did not constitute a proposed regulation because nothing in the preamble was intended by the Agency to constitute an enforceable legal obligation. And it could not, as EPA co-proposed multiple concepts for singular facility types in the November 2021 proposal and requested comment that informed the November 2022 Supplemental Proposal's regulatory text.

For example, in the November 2021 proposal, EPA co-proposed quarterly and semi-annual fugitive emissions surveys for well sites with baseline emissions of 3 or more and less than 8 tons per year of methane. EPA then abandoned the baseline emissions approach in the November 2022 Supplemental Proposal in favor of an equipment threshold. In another example, EPA co-proposed to define affected well facilities in two ways for purposes of the liquids unloading standards. Under one approach, every well that undergoes liquids unloading would be an affected facility; under the other approach, the affected facility would be limited to wells that

undergo liquids unloading that is not designed to eliminate venting. These co-proposals, while limited to a subset of the affected facilities, evidence that EPA intended the November 2021 proposal to be conceptual and a means of informing the November 2022 regulatory text.

The November 2022 proposal is complex and requires affected facilities to parse complicated standards that will inform significant capital expenditures and expensive compliance programs. Given the ultimate complexity of the November 2022 regulatory text and scope of impact, the November 2021 proposal's conceptual offerings did not put the regulated community on notice of the "regulations" in any meaningful way that could inform billions of dollars in capital expenditures and compliance program development. Instead, the regulatory text made available in conjunction with the Supplemental Proposal comprises the proposed regulation because that regulatory text defines the enforceable legal obligations that EPA proposes to impose under this rule.

Thus, even if the original proposal may have satisfied the nominal procedural requirements specified by CAA § 307(d) and APA § 553(b) (which it does not for the reasons explained below), the original proposal was not a proposed "regulation" for purposes of setting the new source trigger date under CAA § 111(a)(2). This is particularly true in light of the clear purpose of CAA § 111(a)(2), which is to put affected facilities that are constructed, reconstructed, or modified after the date of a proposed regulation on notice of the requirements that will apply to those facilities upon the effective date of the final regulation. The absence of proposed regulatory text in the original proposal prevents such affected facilities from knowing with reasonable certainty the precise requirements that might actually apply, and thus prevents them from adequately planning for compliance.

Second, EPA's interpretation of CAA § 307(d) and APA § 553(b) is unreasonable and does not make sense in the broader context of these provisions. For example, EPA argues that the required content of a proposed rule specified in CAA § 307(d)(3) does not expressly require regulatory text, but the corresponding content requirements for a final rule (specified in CAA §§ 307(d)(4)(B)(i), (6)(A), and (6)(B)) similarly do not expressly require regulatory text. By EPA's reasoning, that means that the Agency is not required to provide regulatory text as part of a final rule. That is nonsensical. This is particularly true because the record for judicial review is limited to the materials prescribed by CAA §§ 307(d)(3), (d)(4)(B)(i), (6)(A), and (6)(B). CAA § 307(d)(7)(A). If proposed and final rules do not need to include regulatory text, then regulatory text would not be subject to judicial review. That is contrary to reason and the clear intent of the law.

In short, it is simply not plausible to argue that because CAA § 307(d) does not expressly require a proposed rule to include regulatory text; EPA is not required to make proposed regulatory text available at the time of the 2021 "proposal". When considered as a whole, CAA § 307(d) plainly requires rule text to be available.[96]

Third, and more broadly, EPA and the Biden administration made a political judgment to rush issuance of the original proposed rule because the rule constitutes a prominent plank of the administration's climate change regulatory agenda, and it was deemed expedient to issue the proposed rule in conjunction with the 2021 Conference of the Parties to the United Nations Framework Convention on Climate Change in Glasgow, Scotland.[97] The fact that EPA acknowledged the original proposal would require a Supplemental Proposal with

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[96] EPA cites *Rybachek v. USEPA*, 904 F.2d 1276, 1297 (9th Cir. 1990) as supporting its position that proposed regulatory text is not necessary. That case is inapposite because the court relies on APA § 553(b)(3). While that provision applies to this rulemaking, the more specific requirements of CAA § 307(d) control here.

[97] EPA's press release for the original proposal is available at U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health | US EPA (""As global leaders convene at this pivotal moment in Glasgow for COP26, it is now abundantly clear that America is back and leading by example in confronting the climate crisis with bold ambition," said EPA Administrator Michael S. Regan**.** "With this historic action, EPA is addressing existing sources

actual regulatory text is plain evidence of the rush. The sheer size of the Supplemental Proposal – 146 pages in the Federal Register, *without* regulatory text (which is provided in the docket) – is further mute evidence of the incomplete nature of the original proposal.

We recognize that every administration has the right to set and implement its regulatory agenda. However, this Administration's desire to expedite issuance of the original proposed rule led to compromises in the usual regulatory procedures, including the decision not to make proposed regulatory text available. It would be unreasonable for affected facilities to bear the burden of those compromises. It is also arbitrary and capricious for EPA to decide to issue an admittedly incomplete proposed rule to satisfy political objectives, and, at the same time, assert that it is somehow complete enough to constitute a "proposed rule" that sets the new source trigger date.

As shown in the analysis above, nothing allows or requires EPA to utilize the November 15, 2021 date. Further, the failure of EPA to provide regulatory text in the November 15, 2021 proposal is reason enough for EPA to "warrant exercising" any discretion it does have with respect to the deadline.

Further, by utilizing November 15, 2021 as the relevant demarcation date, EPA will be including a significant number of sources that were new, modified, or reconstructed between November 15, 2021 and December 6, 2022. For a significant number of the affected facilities, operators will be required to retrofit those new, modified or reconstructed sources to comply with the regulations, including regulations not known to operators at the time of construction, modification or reconstruction. Many of these requirements involve either: (1) substantial capital expenditures for equipment (e.g., instrument air skids and/or generators for use of non-emitting pneumatic controllers); (2) engineering design (e.g., storage tanks, design for any covers and closed vent systems, among others); (3) acquisition (along with all other operators) of a substantial number of part and equipment (e.g., flow meters, calorimeters; and (4) substantial in-field resources for retrofits. Not knowing with reasonable certainty what the final rule would require would significantly complicate implementation of compliance measures, cause the rule to be much more costly for such sources than EPA predicts, and frustrate the regulatory purpose of setting the new source trigger date at the date of proposal (which clearly is intended to provide reasonable notice of the ultimate requirements so that planning can be done at the time of construction, reconstruction, or modification.

In addition, since the onset of the COVID pandemic and continuing to this day, there have been substantial supply chain disruptions, difficulty with obtaining parts and equipment and difficulty with finding personnel (either consulting or for employment) that can assist with implementation of the rule. These supply chain and personnel issues will increase given the extensive nature and reach of NSPS OOOOb alone (given all the operators that will need to comply) – not even accounting for other recent regulatory developments at the state and federal level (e.g., BLM waste prevention rule, Colorado regulatory requirements, and New Mexico requirements – to name a few). EPA will compound this supply chain and personnel concern by maintaining November 15, 2021 as the new source trigger date. EPA's motivation is further obscured given the sources constructed, modified or reconstructed between November 15, 2021 and December 6, 2022 are potentially subject to NSPS OOOOa and may ultimately be subject to EG OOOOc. Thus, API believes that EPA not only has the discretion but the requirement to assign December 6, 2022 as the new source applicability date. Even if this were not required, there is ample basis for EPA to do so for all the reasons previously stated.

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from the oil and natural gas industry nationwide, in addition to updating rules for new sources, to ensure robust and lasting cuts in pollution across the country. By building on existing technologies and encouraging innovative new solutions, we are committed to a durable final rule that is anchored in science and the law, that protects communities living near oil and natural gas facilities, and that advances our nation's climate goals under the Paris Agreement."").

12.2 EPA's interest in promoting Environmental Justice is laudable, but EPA must be mindful of the Clean Air Act's boundaries in advancing these goals.

API explained in its comments on the original proposal that we support EPA's attention to potential Environmental Justice (EJ) issues and agree with EPA that the emissions standards prescribed by this rule will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The oil and natural gas industry's top priorities are protecting the public's health and safety – regardless of race, color, national origin, or income – and the environment. We strive to understand, discuss, and appropriately address community concerns with our operations. We are committed to supporting constructive interactions between industry, regulators, and surrounding communities/populations including those that may be disproportionately impacted.

Our comments also explained that, while API supports EPA's EJ goals, the Agency did not provide sufficient detail in the 2021 Proposal to allow API to comment in a meaningful way. EPA has provided additional clarity on two key EJ provisions in the Supplemental Proposal. They are addressed separately below.

12.2.1 Consideration of EJ Impacts in CAA § 111 Standard Setting

First, EPA proposes to require consideration of impacted communities when setting existing source emissions standards that take into consideration remaining useful life and other factors (RULOF). For example, if "a designated facility could be controlled at a certain cost threshold higher than required under the EPA's proposed revisions to the RULOF provision, and such control benefits the communities that would otherwise be adversely impacted by a less stringent standard, the state in accounting for RULOF could choose to use that cost threshold to apply a standard of performance." (87 FR 74824).

EPA believes that it has authority to prescribe such a requirement because "CAA section 111(d) does not specify what are the "other factors" that the EPA's regulations should permit a state to consider", and thus the Agency may "interpret[] this as providing discretion for the EPA to identify the appropriate factors and conditions under which the circumstance may be reasonably invoked in establishing a standard less stringent than the EG." *Id*.

EPA further explains that part of its responsibility in reviewing the adequacy of state CAA § 111(d) existing source emissions control programs is to "determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives." *Id*. "The EPA finds that a lack of consideration to [disparate health and environmental impacts] would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally." *Id*.

Lastly, EPA explains that the "requirement to consider the health and environmental impacts in any standard of performance taking into account RULOF is consistent with the definition of "standard of performance" in CAA section 111(a)(1)" which "requires EPA to take into account health and environmental impacts in determining the BSER." *Id*.

We applaud and support EPA's overall objective of addressing potential disparate impacts. But we are concerned that the Agency's proposal to require such impacts to be addressed when RULOF is considered in setting state standards is not legally supportable.

To begin, the term "other factors" is a generic term in and of itself. But as used in the context of CAA § 111(d), that term does not reasonably mean that EJ may be considered in standard setting. First, CAA § 111(d)(1) states that EPA's regulations "shall permit" states to consider RULOF in setting existing source emissions standards. This

language places responsibility on the states, in the first instance, to determine the “other factors” they deem relevant in setting standards upon consideration of RULOF. EPA’s role is to review the state determination and not to preemptively specify what factors a state may or may not consider. If a state’s identification and consideration of other factors is reasonable, then EPA cannot reject the state’s determination on the grounds that EPA believes the term “other factors” should be given a different meaning. EPA’s proposed approach is inconsistent with the role Congress intended the states to fulfill as part of the CAA’s broader “cooperative federalism” scheme.

Second, the term “other factors” must be interpreted in context. By specifying that states may consider “remaining useful life,” Congress indicated that source-specific factors are relevant to the states’ determinations. Since the term “other factors” is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term “other factors” must be construed in a similar light. This interpretation is particularly true given that “standards of performance” under CAA § 111(a)(1) are technology-based standards that reflect the best system of emissions reduction determined applicable to affected facilities. EPA’s proposed interpretation of “other factors” is inconsistent with this source-specific, technology-based regulatory scheme.

Third, unlike other standards under the CAA, CAA § 111 does not require or allow for standards to be based on an assessment of impacts regarding health or the environment. Where the CAA confers such authority, it does so expressly and usually in a context where criteria exist to determine the adequacy of such standards. For example, CAA § 112(f) requires impacts to health and the environment to be considered in determining whether “MACT”[98]-based NESHAPs are adequately protective to health and the environment. The statute specifies that EPA must provide an “ample margin of safety,” as defined in the Benzene Waste NESHAP. CAA § 112(f)(2)(A), (B). The Title I air quality program is also designed in this fashion – with the National Ambient Air Quality Standards (NAAQS) established as the benchmark for acceptable air quality and the guidepost for formulating appropriate state programs.

Here, CAA § 111 does not provide any indication that EPA must or may consider health or environmental impacts associated with air emissions from affected facilities in determining BSER and in setting emissions standards. For over 50 years, CAA § 111 has properly been construed as a technology-based program designed to prescribe standards based primarily on consideration of the best available technologies that are adequately demonstrated and not cost prohibitive. EPA’s goals here are important but would require standards to be based on impacts analyses of air emissions from affected facilities – an approach that is not incorporated into the CAA § 111 standard setting process.

EPA also states that not considering impacts would be “antithetical to the public health and welfare goals of CAA Section 111(d) and the CAA generally.” There is no doubt that protecting public health and welfare are overarching goals of the CAA. That aspiration does not in itself confer regulatory authority that is not otherwise prescribed by the statute. Congress carefully designed the regulatory tools it intends EPA to use to accomplish an adequate degree of protection to health and welfare. For the reasons explained above, CAA § 111(d) does not require or allow for consideration of health or environmental impacts in standard setting.

Lastly, EPA argues that considering EJ impacts in state standard setting “is consistent with the definition of “standard of performance” in CAA Section 111(a)(1)” and that states must consider such impacts “just as the EPA is statutorily required to take into account these factors in making its BSER determination.” *Id*. at 74824. More specifically, EPA asserts that the definition of “standard of performance” “requires the EPA to take into account health and environmental impacts in determining the BSER.” *Id*. We respectfully disagree, as there is no language

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[98] Maximum Achievable Control technology

in the CAA § 111(a)(1) definition of "standard of performance" that requires or allows health or environmental impacts associated with air emissions from affected facilities to be factored into standard setting.

As explained above, that definition requires standards of performance to primarily be based on technology and cost considerations. The only exception is that "nonair quality health and environmental impact[s] and energy requirements" also must be taken into account in setting standards of performance. CAA § 111(a)(1). The statute thus is clear that the only "health and environmental impacts" that may be considered in setting a standard of performance are ***nonair*** health and environmental impacts. That provision traditionally has been interpreted to require EPA to consider cross-media impacts (e.g., wastewater created by an air emissions scrubber) so as not to create a different environmental issue through technical requirements meant to address air quality. Because the analysis that EPA would require here would focus on air emissions impacts, it cannot be grounded in the requirement to consider ***nonair*** quality health and environmental impacts. Moreover, because the statute specifies that only nonair quality health and environmental impacts may be considered in standard setting, EPA is precluded from interpreting general language in CAA § 111(a)(1) or 111(d)(1) as somehow authorizing consideration of air quality-based health or environmental impacts.

For all of these reasons, EPA should reconsider the proposed requirement to require consideration of EJ impacts when states or EPA implement the RULOF provision.

12.2.2 Requirement that states provide for "meaningful engagement" in their CAA § 111(d) programs.

The Supplemental Proposal provides further details and additional explanation of the proposal to require states to provide for "meaningful engagement" as part of their CAA § 111(d) regulatory programs. According to EPA, "[t]he fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare" (87 FR 74827). As a result, EPA asserts that "a key consideration in the state's development of a state plan, in any significant plan revision, and in the EPA's development of a Federal plan pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare." *Id*. "A robust and meaningful public participation process during plan development is critical to ensuring that the full range of these impacts are understood and considered." *Id*.

The "meaningful engagement" requirement is grounded in the assertion that "a fundamental purpose of the Act's notice and public hearing requirements is for all affected members of the public, and not just a particular subset, to participate in pollution control planning processes that impact their health and welfare." *Id*. at 74828-9. In explaining the legal basis for this requirement, EPA states that "[g]iven the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, the EPA believes it is reasonable to require meaningful engagement as part of the state plan development public participation process in order to further these objectives." "Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations ''as are necessary to carry out [its] functions under [the CAA].'' The proposed meaningful engagement requirements would effectuate the EPA's function under CAA section 111(d) in prescribing a process under which states submit plans to implement the statutory directives of this section." *Id*. at 74829.

API supports full and fair public process in the development and implementation of CAA programs, including state CAA § 111(d) programs. All affected entities should have a reasonable opportunity to know about and participate in the development of regulations that affect their interests. In that light, we offer the following comments on the proposed "meaningful engagement" requirement.

First, CAA § 111(d) states only that EPA shall establish a "procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan." This requirement to establish a "procedure" for "submit[ting] … a plan" unambiguously is directed only at the review and approval process as between the states and EPA and is not directed at the plan development process that must be followed by the state. In other words, CAA § 111(d) directs EPA to emulate only some of the CAA § 110 requirements – not all of them.

Thus, CAA § 111(d) does not allow EPA to impose upon the states any measures related to the process by which they develop their plans. It only provides authority to set up a process by which EPA reviews and approves the adequacy of standards of performance and the measures adopted by the states to implement and enforce such standards.

Second, to the extent that a "reasonable notice" standard applies to the development of state plans under CAA § 111(d), it is the states' responsibility to ascertain what is reasonable – not EPA's. CAA § 111(d) is one of many CAA provisions where Congress intentionally split responsibility between EPA and the states. Indeed, under this "cooperative federalism" scheme, "air pollution control at its source is the primary responsibility of States and local governments." CAA § 101(a)(3). In the earliest days of the CAA, the U.S. Supreme Court confirmed that the CAA "gives the Agency no authority to question the wisdom of a State's choices of emission limitations" if the limitations accomplish the goals of the CAA. *Train v. NRDC*, 421 U.S. 60, 79 (1975).

Implicit in the notion of cooperative federalism is that states not only have wide latitude to determine appropriate emissions limitations, but also have similarly wide latitude in the legal and regulatory processes by which such limitations are established. Thus, to the degree a "reasonable notice" obligation is imposed upon the states by CAA § 111(d), the states have primary authority and responsibility to determine how to implement this requirement. While EPA has responsibility to review and approve state programs, it may not require states to follow what it believes to be the most reasonable notice procedures. Instead, EPA must approve any state notice requirements that are facially reasonable, even if those are not the procedures EPA itself would have selected.

Third, even if EPA has authority to define what constitutes "reasonable notice" during the development of state plans, the proposed "meaningful engagement" requirement goes beyond what EPA may reasonably require. To begin, the term "notice" unambiguously means notification of those with interest in the matter at hand. The proposed requirements to engage with particular groups in particular ways (e.g., states must seek to overcome "barriers to participation" by "pertinent stakeholders") and make targeted outreach go well beyond the nominal statutory obligation of notification. EPA may "think [its] approach makes for better policy, but policy considerations cannot create an ambiguity when the words on the page are clear." *SAS Institute Inc. v. Iancu*, 138 S. Ct. 1348, 1358 (2018). Congress has imposed no explicit requirements and stated no intent in CAA § 111 or anywhere else in the CAA related accomplishing any particular environmental justice goals or outcomes. The word "notice" cannot carry as much meaning as EPA believes it should.

As for CAA § 301, it has long been understood that that provision does not "provide [EPA] Carte blanche authority to promulgate any rules, on any matter relating to the Clean Air Act, in any manner that the [EPA] wishes." *North Carolina v. EPA*, 531 F. 3d 896, 922 (D.C. Cir. 2008) (internal quotes and citations omitted). Here, CAA § 301(a)(1) is inapplicable because creating a new category of procedural requirements is not "necessary" for the Administrator "to carry out his functions under this chapter." CAA § 301(a)(1). As noted above, EPA's intentions are commendable. But the proposed "meaningful engagement" procedures are not "necessary" as that term is used in CAA § 301.

Lastly, EPA's proposed "meaningful engagement" procedures are are not adequately clear and objective. As noted above, Congress has not spoken in the CAA to the issue of environmental justice. EPA and interested parties are without guidance as to whether the issue should be addressed under the CAA and, if so, how.[99] Moreover, EPA's criteria for determining the adequacy of state "meaningful engagement" efforts are vague and EPA's authority under its proposed rules to accept or deny a state's efforts is not bounded by any readily objectively discernable principles. For example, how does EPA determine the manner of required engagement with any particular stakeholders? How does EPA decide what constitutes an actionable "linguistic, cultural, institutional, geographic, [or] other barrier" and, where such barriers are determined to exist, whether the state's proposed approach is sufficient? What measures are needed for state programs to be adequately inclusive? These are all weighty questions that the statute does not expressly address and that EPA leaves fundamentally uncertain in its proposed rule. As a result, the proposed rule is vague, unmoored to the statute, and unless corrected, would be arbitrary and capricious. *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983).

For these reasons, "meaningful engagement" should be encouraged by EPA but cannot be a required element of approvable state CAA § 111(d) programs.

12.3 EPA does not explain the legal basis for its proposal to empower third parties to conduct remote monitoring that may trigger enforceable obligations by affected facilities.

In the original proposal, EPA presented a preliminary concept that would "take advantage of the opportunities presented by the increasing use of [advanced methane detection systems] to help identify and remediate large emission events (commonly known as "super-emitters")" (86 FR 63177). EPA sought comment on "how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event." *Id*.

As we explained at the time, API concurs with the importance of identifying and addressing large emissions events. Emissions from such events have the potential to be much greater than those from normal operations at a given facility. API shares EPA's interest in seeking to reduce the incidence of such large emissions events.

We noted in our comments that the proposed "Super Emitter Response Program" was unique in that it would be the first time under the CAA that EPA asserts authority to create regulatory obligations for affected facilities based on monitoring conducted by unaffiliated third parties. We further noted EPA did not explain the legal basis for establishing such a requirement and explained that an explanation from EPA was essential to understanding whether such a novel provision is legally viable.

Unfortunately, the Supplemental Proposal does not provide the needed explanation. That failure to explain the legal underpinnings of such a key element of the proposal violates the CAA § 307(d)(3)(C) requirement to include as part of the proposed rule "the major legal interpretations underlying the proposed rule." If not cured, it also would render the final rule arbitrary and capricious because EPA would have failed to address and explain a key factor underlying this aspect of the final rule.

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[99] It is notable that the 2022 "Inflation Reduction Act" included the most significant amendments to the CAA in decades and specifically targeted Environmental Justice concerns, yet Congress stopped short of amending CAA § 111 or the other existing substantive CAA programs to require or allow consideration of EJ. In other words, Congress expansively addressed EJ, but did so by providing copious funding to address the issue and chose not to create obligation or authority to otherwise address or consider EJ in implementing the existing CAA substantive programs.

To be sure, the Supplemental Proposal includes a lengthy discussion in the preamble called the "Statutory Basis of Super-Emitter Program" (87 FR 74752). For some four pages, EPA delves deeply into two explanations as to how it believes "the proposed super-emitter response program … fits within the EPA's authority under section 111 of the CAA." *Id*. In particular, EPA explains how the program might be justified by treating super-emitting events as an affected facility warranting a § 111 emissions standard and, alternatively, how the "super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule" (either as an added compliance assurance measure or as additional equipment leak work practices). *Id*. at 74752-4.

As for those suggestions, API disagrees with EPA's contention that it has authority to treat super-emitting events as an affected facility warranting a § 111 standard of performance. Rather, at most, EPA has the authority to consider identification of super-emitter events as "monitoring" for an affected facility. As such, super-emitters may only be regulated at facilities that already are subject to NSPS OOOOb or EG OOOOc for other reasons. In other words, if a thief hatch on an NSPS OOOOb storage vessel were left open, it could (if meeting the threshold – and subject to the legal concerns set forth below) be considered a super-emitter, and EPA could require corrective action to close the thief hatch. This would be similar for emissions above the threshold from an unlit flare or control device that is mandated by NSPS OOOOb or EG OOOOc (once applicable). However, a super-emitter cannot arise from equipment at a stationary source that is not already an affected facility.

In other words, if an aerial survey identified emissions from a thief hatch on a storage vessel that is not subject to NSPS OOOOb, and the storage vessel is not yet subject to EG OOOOc, then this cannot be a super-emitter affected facility subject to the regulations and for which an operator has to take corrective action. EPA's preamble appears to support this approach in several places, but does not specifically state this in the rule. Thus, as written, it appears that one could identify a super-emitter at a stationary source that has no affected facilities or from equipment that is not an affected facility. EPA has not justified that super-emitters – many of which are malfunctions – are or can be independently considered "affected facilities" under CAA § 111.

An in any event, nowhere in this lengthy discussion – nor in any other part of the preamble or supporting documents – does EPA explain where in the CAA it finds authority to empower third parties to submit monitoring information to an affected/designated facility that triggers regulatory obligations for the facility under the rule. The need for a legal explanation is particularly necessary here, given that this is the first time that EPA has sought to establish such a requirement under CAA § 111 or, to our knowledge, under the CAA as a whole.

We also note that EPA provides a lengthy discussion of the policy rationale that stands behind the proposed Super-Emitter Response Program, including an extensive explanation of how EPA believes that "[t]he design of the super-emitter response program ensures that the EPA will make all of the critical policy decisions and fully oversee the program." *Id*. at 74749-51. In EPA's view, "the qualified third party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications within the limited confines that EPA has authorized." *Id*. at 74750. Moreover, such notifications "originating from third parties would not represent the initiation of an enforcement action by the EPA or a delegated authority." These arguments indirectly speak to EPA's assertion of possible legal authority, but the policy rationale by itself cannot legally justify EPA's novel proposal to empower citizens to develop and submit information that triggers legal obligations for affected/designated facilities.

We lastly note that, in our comments on the original proposal, we explained that CAA § 304 expressly prescribes a role for citizens in CAA implementation by authorizing them to file civil lawsuits challenging alleged violations of, among other things, CAA § 111 emissions standards. We pointed out that Congress did not provide similar express

language in CAA § 111 or elsewhere in the CAA authorizing citizen monitoring as provided in the proposed super-emitter response program. In this context, the absence of such language should be construed as a limitation on EPA's authority to allow such monitoring and such an absence is not an implicit delegation of authority from Congress to EPA.

As a further note on the relevance of CAA § 304, that section prescribes strict criteria for obtaining injunctive relief to address alleged CAA violations – including prior notice, opportunity for the government to take the lead on an enforcement action, standing to bring an enforcement case, proof of liability, and sufficient rationale to support injunctive relief. The proposal runs counter to CAA § 304 by enabling citizens to obtain injunctive relief through the super-emitter response program (in this case, investigation, corrective action, root cause analysis, and related measures) without satisfying the procedural and substantive criteria that must be met to obtain such relief under CAA § 304.

12.4 The 100 kg/hr emissions threshold for defining a "super-emitter" is not adequately justified.

As a wholly different concern, EPA proposes to "define a super-emitter emissions event as any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater." *Id*. at 74749. While EPA provides a lengthy explanation of how that threshold was determined and why EPA believes it is appropriate, the overarching rationale is that the Agency believes that this threshold captures "very large emissions events." *Id*. Indeed, the term "super-emitter" clearly was coined to describe the intended scope of coverage.

Yet just a few months ago, when addressing essentially the same issue under Subpart W of the Greenhouse Gas Reporting Program, EPA proposed to establish a new reporting requirement for "other large release events," which EPA proposed to define as "events that release at least 250 mtCO_2e per event." 87 Fed. Reg. 36920, 36982 (June 21, 2022). In explaining its rationale for setting this threshold, EPA explains that, "[w]hile some sources covered by subpart W methodologies, such as equipment leaks, may represent ''malfunctioning'' equipment, these sources are ubiquitous across the oil and gas sector [and] are generally small." *Id*. The proposed 250 mt reporting threshold is intended to capture "large emissions events." *Id*. EPA derived the value by assessing "other emissions sources that [it] considered large." *Id*. The threshold was expressly designed to be considerably lower than the emissions rates estimated for the largest release events (e.g., Aliso Canyon or Ohio well blowouts), and compares favorably to a similar reporting requirement under Subpart Y for petroleum refinery flares. *Id*. at 36983.

Despite the obvious similarities between the proposed Subpart W large emissions event proposal and the proposed NSPS OOOOb and EG OOOOc super-emitter proposal, EPA fails to mention the Subpart W proposal when explaining in the NSPS OOOOb and EG OOOOc proposal its rationale for establishing the emissions threshold for super-emitting events. The omission is particularly striking given the significant differences between the two proposals as to what EPA believes to be a large-emitting event. For example, EPA proposes to apply a kg/hr metric in NSPS OOOOb and EG OOOOc versus an event-based metric for Subpart W. Additionally, the proposed NSPS OOOOb and EG OOOOc threshold of 100 kg/hr is facially much lower than the 250 mt per event threshold in Subpart W. The Subpart OOOOb and OOOOc proposal would define events as "super-emitting" that EPA in the Subpart W proposal dismisses as "ubiquitous" and "generally small."

Clearly, the two proposed rules are contradictory in many relevant aspects. EPA has not provided any explanation in the NSPS OOOOb and EG OOOOc original or Supplemental Proposals as to why the proposed definition of "super-emitter" makes sense in light of the proposed rules for large event release reporting under Subpart W.

Lack of such an explanation would render this aspect of the final NSPS OOOOb and EG OOOOc rule arbitrary and capricious. Moreover, even if EPA provides an explanation in the final rule, the definition of "super-emitter" is of central relevance to the Super-Emitter Response Program and, thus, failure to provide an opportunity for public notice and comment on its explanation would violate the CAA § 307(d) procedural rulemaking requirements.

12.5 EPA's proposed approach to reconciling the applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc is contrary to law and unreasonable.

In our comments on the original proposal, we noted that the proposal did not include any discussion or analysis of the complex issues surrounding the applicability of the various NSPS OOOO subparts. We pointed in particular to the complexities related to the fact that the various subparts do not completely overlap – Subpart OOOO applies only to volatile organic compounds (VOCs), Subparts OOOOa and OOOOb apply to VOCs and greenhouse gases (GHGs), and EG OOOOc applies only to GHGs. Also, the affected/designated facilities are not the same under these rules. We also highlighted the question of whether a source that is an affected facility that is regulated as a new source under an existing NSPS can also be an "existing" facility under a subsequent CAA § 111(d) rule. Another important omission was any citation or explanation/analysis by EPA of the applicable law.

The Supplemental Proposal does not resolve these issues. To be sure, EPA provides an explanation of how it believes "the proposed EG OOOOc [will] impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa." (87 FR 74716). But that explanation is fundamentally incomplete because EPA still does not provide any legal analysis explaining how or why its proposed analysis is required or allowed under the law. The full extent of EPA's legal discussion on this topic is the conclusory assertion that:

> *Under CAA section 111, a source is either new, i.e., construction, reconstruction, or modification commenced after a proposed NSPS is published in the Federal Register (CAA section 111(a)(1)), or existing, i.e., any source other than a new source (CAA section 111(a)(6)). Accordingly, any source that is not subject to the proposed NSPS OOOOb as described is an existing source subject to EG OOOOc.*

Id. at 74716.

That simple explanation does not provide sufficient detail on the key legal questions we presented in our prior comments. For example, EPA does not explain how the law requires or can be interpreted to require a source to be regulated as a "new" source under a prior NSPS and, at the same time, be regulated as an "existing" source under a subsequent CAA § 111(d) program. It is clear that EPA presumes that this is how the law works. For example, the Agency repeatedly asserts that Subpart OOOOc standards "would satisfy compliance with" previously applicable NSPS – clearly implying that both standards would apply. See *Id.* at 74716-8. But the Supplemental Proposal does not explain why this outcome (applicability of both new and existing source standards to the same affected/designated facility) must or may be prescribed under the law.

EPA's silence on this important matter is particularly pronounced because EPA has never taken the position a that previously applicable NSPS continues to apply to an affected facility that triggers the applicability of a subsequent standard. For example, VOC emissions from storage vessels are regulated under both Subpart OOOO and Subpart OOOOa. It is easily conceivable that a given storage vessel might have triggered Subpart OOOO because it was constructed one month after that standard was proposed and then subsequently triggered Subpart OOOOa because the storage vessel was modified two months after that standard was proposed. It is well understood that, in such a circumstance, the Subpart OOOO storage vessel requirements cease to apply after the corresponding

Subpart OOOOa requirements are triggered. The approach to reconciling applicability suggested in the Supplemental Proposal cannot be reconciled with EPA's historic practice.

More broadly, EPA fails in both the original and Supplemental Proposals to explain how the law must or can be construed to determine what standard applies to a given source when: (1) the source is regulated as a new source under a prior version of an NSPS (such as Subpart OOOO) and then triggers a subsequent version of that new source standard (such as Subpart OOOOa); (2) the source is regulated as a new source under an existing new source standard (such as Subpart OOOO or OOOOa) and is in existence when a subsequent Section 111(d) existing source standard is proposed (such as EG OOOOc) and subsequently take effect; and (3) a source is regulated as an existing source under a Section 111(d) standard (such as EG OOOOc) and is subsequently modified or reconstructed such that it triggers a corresponding new source standard (such as NSPS OOOOb).

In sum, EPA fails to acknowledge the complexities and ambiguities as to how the law applies to this situation and fails to provide relevant legal analysis on these points. Unless EPA corrects these problems, the final rule will be both procedurally flawed (for failure to satisfy the CAA § 307(d)(3) obligation for EPA to address in the proposed rule that major legal interpretations underlying the proposed rule and to provide an opportunity for public comment) and arbitrary and capricious (for failure to address key factors underlying applicability of the various subparts). We note the legal basis for the applicability scheme for these rules is an issue of central relevance because the scope of applicability is fundamental to proper implementation and coordination of these rules.

12.6 EPA must provide more flexibility for approving state programs.

The Supplemental Proposal includes a lengthy discussion of the approach and criteria by which EPA proposes to review and approve/disapprove state CAA § 111(d) existing source programs. We have comments and recommendations on several elements of EPA's proposed approach.

All of our comments flow from the fundamental guiding principle that EPA is required to approve state programs that satisfy CAA § 111(d) standard setting criteria and cannot approve state programs that do not meet those criteria.[100] EPA correctly sums up this principle when it states "that its authority is constrained to approving measures which comport with applicable statutory requirements" (87 FR 74826 n. 274). The problems with EPA's proposal regarding approval of state programs all are grounded in violations of this principle.

To begin, EPA exceeds its authority by seeking in many places to impose its own preferences on state programs rather than recognizing that it must approve any state program that meets the statutory criteria – even programs that include elements that EPA itself would not choose, but that objectively do meet statutory standard setting requirements. In other words, if a state program meets express statutory requirements or otherwise is grounded on a reasonable construction of statutory requirements, EPA has no choice but to approve the program.

For example, EPA repeatedly and wrongly asserts that its "presumptive standards" must be used to judge the adequacy of state programs. See, e.g., *Id*. at 74812 ("a state program must establish standards of performance that are in the same form as the presumptive standards"); *Id*. ("EPA is also proposing to interpret CAA section 111 to authorize states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards"). Using EPA's presumptive standards as a measure of acceptability is wrong because a state's obligation under CAA § 111(d) is to establish standards of performance based on BSER.

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[100] The only other state obligation is to satisfy the nominal procedural requirements that EPA establishes for submission, review, and approval of state CAA § 111(d) programs.

CAA §§ 111(a)(1) and (d)(1). EPA's "presumptive standards" do not constitute BSER. Rather, they represent EPA's notion of what emissions standard might reasonably satisfy EPA's BSER determinations. But the statute unambiguously provides that states have authority and responsibility to fashion a standard that meets BSER and is not limited to the "presumptive standard" that EPA thinks is best.

Notably, EPA clearly understands that is what the statute requires. EPA itself states that "Section 111(d) does not, by its terms, preclude states from having flexibility in determining which measures will best achieve compliance with the EPA's emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion" (87 FR 74812). EPA's acknowledgment that it is the states' obligation to determine what measures "best" satisfy EPA's BSER determination is a correct statement of the law and contradicts the idea that EPA gets to decide what is "best" and impose that judgment on the states.

On a related note, EPA here indicates its commitment to faithfully implementing the "framework of cooperative federalism that CAA section 111(d) establishes," which necessarily requires EPA to defer to (and approve) state measures that satisfy the law, even when such measures do not satisfy EPA's own preferences. See also *Id*. at 74826 (EPA proposing to defer to the state's discretion to impose more costly controls). Yet on the other hand, a primary rationale for the proposed prescriptive measures for reviewing and approving/denying state programs is concern about inconsistency from state to state (e.g., *id*. at 74818 ("two states could consider RULOF for two identically situated designated facilities and apply completely different standards of performance on the basis of the same factors")) and the possibility that certain state programs will be less stringent than EPA believes they should be (e.g., *id*. at 74817 (lack of a clear framework might allow states to "set less stringent standards that could effectively undermine the overall presumptive level of stringency envisioned by the EPA's BSER determination and render it meaningless")). EPA cannot have it both ways – i.e., support state flexibility when it promotes EPA's preferred outcomes and discourage state flexibility when needed to achieve such outcomes. Such an inconsistent approach is facially arbitrary. It is easily resolved by allowing the state flexibility that EPA acknowledges to exist and, in any event, that is demanded by the statute.

Another flaw in EPA's approach is its proposal to give substantive meaning to the statutory obligation that it must approve state plans that are "satisfactory." CAA § 111(d)(2)(A). For example, EPA explains that "it is the EPA's responsibility to determine whether a state plan is "satisfactory" (87 FR 74818). EPA further explains that "the most reasonable interpretation of a ''satisfactory plan'' is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d)." *Id*. See also *id*. at 74824 ("CAA section 111(d)(2)'s requirement that the EPA determine whether a state plan is ''satisfactory'' applies to such plan's consideration of RULOF in applying a standard of performance to a particular facility. Accordingly, the EPA must determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives.").

So, by EPA's reasoning, all elements of its CAA § 111(d) implementing regulations become mandatory state obligations because, if a state does not in EPA's eyes satisfy the regulations, the state program is not "satisfactory" to EPA. Similarly, EPA gets to decide whether a state plan is "satisfactory" based on EPA's judgment as to whether the plan meets EPA's conception of the "overall health and welfare objectives" of CAA § 111(d). In other words, EPA uses the term "satisfactory" to bootstrap its own policy and legal preferences into mandatory approvability criteria.

EPA's interpretation is inconsistent with the plain words of the statute and, in any event, unreasonably expands EPA's authority to prescribe or prohibit particular outcomes under state CAA § 111(d) programs. The statute

simply says that state plans must be "satisfactory." The word "satisfactory" naturally connotes that EPA must approve any state plan that meets the statutory standard setting criteria and that otherwise meet the nominal procedural rules that EPA is required to establish to guide submission and review/approval of state plans. The word "satisfactory" does not reasonably confer upon EPA the authority to demand particular outcomes (e.g., meeting EPA's self-determined "health and welfare objectives") or to impose substantive constraints not otherwise specified by CAA § 111(d). EPA's effort to give more meaning to the word "satisfactory" is inconsistent with the law and a misplaced effort to expand the Agency's authority under CAA § 111(d).

Lastly, EPA explains that when a state decides to establish a standard of performance based on consideration of remaining useful life and other factors, it must "determine and include, as part of the plan submission, a source-specific BSER for the designated facility" (87 FR 74821). EPA then prescribes criteria that the state must follow in determining BSER and setting a corresponding emissions standard. *Id*. This is the first time in this rulemaking (and, to our knowledge, the first time ever) that EPA has interpreted the statute as authorizing and requiring a state to conduct a BSER analysis under CAA § 111(d) rather than setting standards of performance based on an EPA BSER determination.

We agree with EPA that, when a state considers RULOF in setting emissions standards for a particular source or group of sources, it necessarily must conduct a BSER analysis as part of its analysis. When a state considers RULOF, EPA's own BSER analysis ceases to have meaning because fundamental elements of that analysis – such as the cost assessment and determination that a particular emissions control method is feasible or has been adequately demonstrated – cease to apply to the source(s) covered by the state RULOF analysis.

EPA asserts that "the statute requires the EPA to determine the BSER by considering control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating: (1) The cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology" and that "a state must also consider all these factors in applying RULOF for that source." *Id*. We agree that the statute requires the first three criteria to be considered in determining BSER. We agree that application of these criteria is consistent with the principle that state CAA § 111(d) plans must meet the statutory standard setting criteria. We do not agree that the statute specifies or requires that BSER also must be based on an assessment of "the amount of reductions" or "advancement of technology." A state has the discretion to consider these factors, but EPA cannot impose these factors on a state because the statute itself does not require that they be considered.

EPA goes on to assert that a state BSER analysis "must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG using the five criteria noted above." *Id*. We disagree. The state clearly must determine BSER based on the express statutory criteria. But the law does not require a state BSER analysis to "identify all control technologies available for the source," "use the same metrics," or provide an evaluation "in the same manner" as EPA used in developing its BSER analysis. These may represent EPA's preferred method of determining BSER, but nothing in the law requires a state to follow EPA's preferred method or authorizes EPA to reject a state standard that is based on a BSER determination that employs a different approach than EPA's.

12.7 EPA does not have authority to approve more stringent state programs that are based on consideration of remaining useful life and other factors.

In the original proposal, EPA offered an extensive explanation of why it now believes it has authority to approve state § 111(d) programs that are more stringent than would be required by application of the BSER determined by

EPA. That position is expanded in the Supplemental Proposal by EPA's assertion that "states may consider RULOF to include more stringent standards of performance in their state plans" (87 FR 74825). This position represents a complete reversal of the current Subpart B provision limiting application of "RULOF" to establishing less stringent measures (See 86 FR 63251).

EPA now asserts that the term "other factors" is ambiguous and that EPA "may reasonably interpret[] this phrase as authorizing states to consider other factors in exercising their discretion to apply a more stringent standard to a particular source" (87 FR 74825). Moreover, EPA now rejects the idea that the § 111(d) Subpart B variance provisions are relevant in interpreting the scope of the Agency's authority to approve more stringent standards based on consideration of RULOF. *Id*. EPA also rejects its prior analysis of the legislative history on the grounds that it provides no meaningful guidance to EPA. *Id*. at 74826. Lastly, EPA argues that its new interpretation is consistent with the purposes of CAA § 111(d) – i.e., "to require emission reductions from existing sources for certain pollutants that endanger public health or welfare." *Id*.

EPA's attempt to reverse its position here is misplaced and is not supported by the law. First, as we discuss above, the term "other factors" is not a carte blanche invitation from Congress for EPA to create whatever plausibly "reasonable" new authorities or constraints it might conceive. The term "other factors" must be interpreted in context. As EPA itself explains, the term "remaining useful life … is a factor that inherently suggests a less stringent standard." *Id*. In this context, it stands to reason that Congress intended the term "other factors" to be interpreted such that "other factors" are applied in the same way (to reduce rather than increase stringency). Because the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term "other factors" must be construed in this manner.

Second, EPA's position is grounded in its assertion that states are not required "to conduct a source-specific BSER analysis for purposes of applying a more stringent standard" because "[s]o long as the standard will achieve equivalent or better emission reductions than required by EG OOOOc, the EPA believes it is appropriate to defer to the state's discretion to, e.g., choose to impose more costly controls on an individual source." *Id*. at n. 273. At the same time, EPA correctly notes that "its authority is constrained to approving measures which comport with applicable statutory requirements." *Id*. at n. 274; see also *Id*. at 74813 (EPA may not approve and thereby "federalize" state programs that apply to pollutants and/or affected facilities not covered by Subpart OOOOc).

It is inconsistent and arbitrary for EPA to assert that a state must conduct a new source-specific BSER analysis if it wants to use RULOF to establish a less stringent standard than would be required under EPA's BSER determination (see *Id.* at 74821), while a state is not similarly constrained when establishing more stringent standards. EPA's assertion that a more stringent standard does not require a BSER analysis because it "will achieve equivalent or better emissions reductions than required by EG OOOOc" cannot be squared with the requirement that alternative state measures must "comport with applicable statutory requirements" – which in this case include the unambiguous requirement that BSER and corresponding emissions standards must be demonstrated in practice and cost effective. EPA's suggestion that it may defer to (and approve) more stringent state requirements simply because they are more stringent is wrong because that approach does not ensure that the more stringent standards meet the statutory standard-setting criteria.

12.8 The proposed well closure requirements are not needed as a practical matter and mostly beyond EPA's authority as a legal matter.

In the original proposal, EPA raised in concept the possibility of setting standards "to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged

ineffectively" (86 FR 63240). We explained in our comments that emissions from abandoned wells are not as great as EPA suggests and that issues related to well closure are more appropriately addressed by the states and BLM. We also explained that, if EPA decided to move ahead with such standards, the possibility of requiring a demonstration of financial capacity should not be a part of that proposed rule given EPA has no authority under the Clean Air Act to impose a financial assurance requirement.

In the Supplemental Proposal, EPA proposes regulations governing well closures in both NSPS OOOOb and EG OOOOc (87 FR 74736). The proposed rules closely track the concept outlined in the original proposal – including a requirement for developing and submitting a well closure plan within 30 days of the cessation of production from all wells at a well site, which must describe the steps that will be taken to close the well, proof of financial assurance, and a schedule for completing the closure. *Id*. Monitoring must be conducted after closure to demonstrate that there are no emissions from the closed well. *Id*. And changes in ownership must be reported on an annual basis during the life of a well. *Id*.

In light of this proposal, we reiterate our prior argument that the CAA does not grant EPA authority to impose financial assurance requirements.[101] We add that EPA did not respond to these comments in the Supplemental Proposal. We further note that EPA did not explain the legal basis for the proposed financial assurance requirements in either the original or Supplemental Proposal. Indeed, EPA cites no legal authority and provides no legal analysis for any aspect of the proposed well closure standards. Such an explanation is needed for such a key and novel aspect of this proposed rule so that interested parties have the opportunity to formulate and submit comments on EPA's legal rationale. CAA § 307(d)(3). The final rule will be procedurally deficient if EPA does not cure this problem.

Lastly, EPA provides little new evidence or arguments in the Supplemental Proposal as to why well closure standards are warranted. EPA appears to rely on the more extensive discussion provided in the original proposal. Notably, that discussion focuses on "abandoned wells" (i.e., "oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells") "that are not plugged or are plugged ineffectively." (86 FR 63240). The discussion particularly targets "orphan wells" – i.e., those that have been abandoned and for which "there is no responsible owner." *Id*. EPA explains that the proposed well closure standards constitute a "potential strateg[y] to reduce emissions from these sources." *Id*. at 63241.

EPA explains in passing that states and other federal government agencies regulate well closures and have programs to address abandoned and orphan wells. Yet EPA does not conduct an in-depth assessment of these programs or make any attempt to distinguish how much of the perceived problem with abandoned or orphan wells relates to wells that pre-date the current federal and state programs versus wells that are regulated by such programs. In other words, EPA asserts that well closure standards are needed to address the problem of emissions from abandoned or orphan wells but does not determine that current state and federal programs are somehow deficient and, therefore, need to be supplemented by EPA standards going forward.

If EPA had delved more deeply into the current state of affairs, it would have seen that industry, states, and other federal government agencies are making great progress in addressing abandoned and orphaned wells. For example, the federal Bureau of Land Management highlights on its website its extensive regulatory and non-regulatory efforts to address orphan wells, including the hundreds of millions of dollars allocated by Congress in

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[101] Comment 10.1.1 on page 40 in EPA-HQ-OAR-2021-0317-0808

the recent "Bipartisan Infrastructure Law" to support tribal, state, and federal efforts in this area. EPA does not even mention the Bipartisan Infrastructure Law in the original or Supplemental Proposals.

Before finalizing the proposed well closure standards, EPA needs to consider more closely the current regulatory landscape, the extensive non-regulatory measures focused on abandoned and orphaned wells, and the expansive voluntary efforts by industry to address this important issue. Those factors are critical to understanding whether EPA rules are needed and, if so, how they should be designed and implemented.

12.9 The Supplemental Proposal would impose unreasonable, impractical, and unduly burdensome certification requirements.

The applicability of several elements of the proposed rule depends on a certification of technical infeasibility that must be executed by a professional engineer or other qualified individual. Examples include the use of an emissions control device to handle associated gas (see, e.g., proposed § 60.5377b(b)(2)), the continued use of pneumatic pumps driven by natural gas (see, e.g., § 60.5393b(c)), and the use of emitting gas well unloading methods (see, e.g., §60.5376b(c)(2)(ii)(B)(2)). EPA imposes these certification requirements out of concern about the possible "abuse" of these provisions such that they might open a "loophole" in the regulations (87 FR 74776). EPA stresses that it, "wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties." *Id*. Thus, the proposal raises the serious prospect of individual, personal liability, not only for fraudulent certification, but also for technically erroneous (i.e., "significantly flawed") certifications.

As we discussed in our comments on the original proposal, we support these opt out provisions as a practical matter. We agree that non-emitting measures and methods should be used where they are technically feasible and cost effective. But EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. The proposed alternative measures are a common-sense solution.

But our comments on the original proposal also expressed the concern that EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating opt outs. We pointed out that the need to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA §111 because non-emitting standards are not "adequately demonstrated" if opt outs are needed to make them feasible and workable.

We reiterate those concerns about the legal basis for EPA's opt-out approach because onerous and potentially punitive certification requirements make the opt out approach even more legally tenuous. To begin, such certification requirements will significantly limit the situations where an opt out can be employed. As a result, what otherwise might be a reasonably viable alternative to an unworkable zero-emissions standard is unnecessarily complicated by strict certification requirements tied to an undefined standard that will be difficult to apply and limit the usefulness of the alternative. That heightens the concern that creating an opt out is unlawful circumvention of the obligation to demonstrate that BSER and the corresponding standards of performance are adequately demonstrated and cost effective.

Moreover, the proposed certification requirements are unreasonably onerous because, in each case, the certifying individual must essentially prove a negative – that the otherwise applicable zero-emissions approaches

are “technically infeasible.” There is no definition of technical infeasibility in the proposed rules, but the words could be construed as setting an exceedingly high bar, such that a given non-emitting technique is “infeasible” based solely on a technical assessment of whether it can theoretically be physically applied in the given situation. So, for example, that might require a non-emitting technology to be applied because it is technically theoretically possible, even though it would be inordinately expensive. This outcome would not be lawful because it would violate the statutory requirement that BSER and the corresponding standard of performance must be cost effective.

And, in any event, a “technical infeasibility” standard allows for second guessing by regulators or citizen enforcers, which invites a “battle of the experts” in potential enforcement actions. All of this diminishes the possibility that the opts outs can be implemented with reasonable certainty.

Lastly, the express threat of possible personal liability on the part of certifiers surely will limit the number of individuals willing to make the needed certifications, particularly in light of the uncertainties described above about what will be needed as a practical matter to demonstrate “technical infeasibility.” The clear opportunity and possibility of second guessing will be further material disincentives.

We provide here three recommended solutions to these problems. First, rather than creating opt outs that require case-specific certification, EPA should establish the opt outs in the final regulation as regulatory alternatives that may be employed if specified criteria in the rule are met. This is the usual method of prescribing standards of performance and regulatory compliance alternatives, and it would not be difficult for EPA to structure the rule in this fashion.

Second, as explained above, one of the legal flaws in EPA’s opt-out scheme is that technical feasibility is the only governing criterion. The cost of implementing the default zero-emitting standard is not a consideration. As a result, the proposed opt-out approach unlawfully evades the obligation that cost must be considered in prescribing CAA § 111 standards of performance. This flaw is easily cured by including cost as a consideration in implementing the opt-out provisions.

Third, if EPA retains the requirement for case-specific certifications, EPA should revise the required certification. The proposed regulatory text of each certification includes the following sentence: “Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.” See, e.g., § 60.5377b(b)(2). This should be revised to specify that the certification is based on “reasonably inquiry,” as is required for certifications under the Title V operating permit program. The revised certification could read as follows: “Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, ….” A “reasonable inquiry” standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

12.10 EPA should not define and impose practical enforceability requirements without first developing a consistent approach for all EPA programs.

In the original proposal, EPA proposed “to include a definition for a ‘legally and practicably enforceable limit’ as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules” (86 FR 63201). EPA explained that “[t]he intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected

facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy." *Id*.

In our comments on that proposal, we urged EPA to defer final action on the proposed definition until such time as the Agency undertakes a broad-based rule that would provide a single, consistent approach across all affected CAA programs. Such an approach would prevent potential inconsistencies among the various CAA programs (e.g., an effective emissions limit used to avoid major New Source Review (NSR) permitting might, at the same time, not be effective for purposes of the OOOOb and/or EG OOOOc storage vessel standards); would avoid the possible implication that the "effectiveness" criteria established under EG OOOOc should be applied under other CAA programs (i.e., how can an emission limit be both effective and not effective at the same time), and allow EPA to establish reasonable transition rules so that affected sources and states have time to revise existing emissions limitations as needed to meet the new effectiveness criteria.

In addition, few existing sources have express emissions limitations for methane or GHGs. Yet, EPA has newly proposed a 20 tpy methane applicability trigger for the Subpart OOOOb and OOOOc storage vessel standards (in addition to the 6 tpy VOC trigger) (87 FR 74800). As a result, many potentially affected/designated facilities likely will seek to rely on VOC emissions limitations as a surrogate for methane emissions. The use of surrogates in establishing effective potential to emit (PTE) limits is another cross-cutting issue for which EPA should establish a unitary CAA approach rather than the proposed piecemeal, rule-by-rule approach.

We raise these issues again because EPA recently announced its intention to issue national guidance on establishing effective limits on potential to emit.[102] That effort appears to be driven by a July 2021 report from the EPA Inspector General that criticized the Office of Air and Radiation for not responding to a series of 1990's era D.C. Circuit decision that vacated or remanded the then "federal enforceability" criteria that applied across EPA's CAA regulatory programs.[103] EPA intends to issue national guidance by October 2023.

EPA's announced plan to establish national rules for effective limits on PTE and to do so in the relative near future lends strong additional support to our request that EPA should not address these issues in a premature and piecemeal fashion in the EG OOOOc rule.

13.0 Other General Comments

13.1 Due to the unreasonably short duration of the comment period for the Supplemental Proposal, API has been unable to respond to all of EPA's comment solicitations.

The proposed NSPS OOOOb and EG OOOOc are both complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, many stakeholders requested an extension of the comment period in order to provide the agency with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. Concurrent with this rulemaking there are additional and overlapping regulatory developments on this subject matter including the Inflation Reduction Act Methane Emissions Reduction Program, EPA's Redesignation of Portions of the Permian Basin for the 2015 Ozone

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[102] *NAAQS, Regional Haze & Permit Program Implementation Updates*, Presentation by Scott Mathias, Director Air Quality Policy Division, OAQPS, to AAPCA Fall Meeting (Sept. 29, 2022).

[103] *EPA Should Conduct More Oversight of Synthetic-Minor-Source Permitting to Assure Permits Adhere to EPA Guidance, Report No. 21-P-0175*, memorandum from Sean W. O'Donnell to Joseph Goffman (July 8, 2021) at 17.

National Ambient Air Quality Standards, EPA's Proposed Updates to the National Ambient Air Quality Standards for PM and the Bureau of Land Management's proposed Waste Prevention Rule that all must be reviewed in accordance with the overlapping aspects of these various actions.

To provide a complete set of comments on a rulemaking as broad, impactful, precedent setting, and complex as proposed within NSPS OOOOb and EG OOOOc, API requested an additional 60 days to gather information and submit comments. Not only did EPA decline API's and other stakeholders' reasonable request for a 60-day extension of the comment period, EPA did not grant even an additional two weeks as the Agency did for the initial proposal[104], which was smaller than the Supplemental Proposal. As we have stated in Comment 12.1, we recognize that every administration has the right to set and implement its regulatory agenda. Nevertheless, that this Administration would expedite issuance of the original proposed rule to align with COP26[105], delay issuance of the Supplemental Proposal to align with COP27[106], and then deny the request of pertinent stakeholders to have adequate time to provide fully-informed feedback to EPA, undermines this Administration's stated goals of reducing emissions in the service of political optics. API has developed as complete a set of comments provided herein as time has allowed. However, much of the information EPA requested, as well as additional information API wanted to provide, is not included herein due to the arbitrary and unnecessarily imposed timing constraints of the comment period for the Supplemental Proposal. We restate our industry's shared goal with EPA of reducing emissions from oil and natural gas operations across the value chain. We remain concerned that this Administration will rush to the completion of a final rule that is not cost-effective, technically feasible, or legally sound. We strongly encourage EPA to adopt the recommendations in our comments to enable the final rule to meet these critically important criteria.

13.2 EPA should reduce burden associated with the collective recordkeeping and reporting requirements.

Proposed NSPS OOOOb and EG OOOOc include onerous recordkeeping and reporting that exceed typical levels of compliance assurance and are a significant cost to operators to track and maintain. EPA should continue to focus on having operators track the most necessary information to obtain assurance.

In this proposal,

- EPA increased the recordkeeping and reporting requirements without adequately justifying increased costs with respect to the administrative burden these proposed changes would require, including numerous technical demonstrations and engineering statements. Increased costs associated with administrative burden are disproportional to benefit – because benefit is marginal when compared to other mechanisms that are already in place and proposed elsewhere in this rulemaking that focus on necessary information to assist in ensuring compliance.
- EPA continues to ignore the scale of affected/designated facilities that will become subject to these provisions over time, which is well over the tens of thousands.
- EPA has included reporting requirements that are outside the Agency's jurisdiction in requiring details on well ownership transfers.

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[104] https://www.federalregister.gov/documents/2021/12/17/2021-27312/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for

[105] https://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health

[106] https://www.epa.gov/newsreleases/biden-harris-administration-strengthens-proposal-cut-methane-pollution-protect

API recognizes that it is appropriate to maintain sufficient records to demonstrate compliance. However, it is API's view that it is excessive to require such a significant level of detail to be both documented and submitted for all of the affected/designated facilities in this proposal. EPA should simplify the recordkeeping and reporting requirements to those that assure compliance without additional administrative burden. Only elements needed for compliance assurance should be requested within the annual report as supporting records retained by companies can be made available upon request from the Agency.

API has provided some initial comments on certain recordkeeping and reporting aspects of proposed NSPS OOOOb and EG OOOOc throughout this comment letter, but due to the short comment period have not had adequate time to fully assess the impact of what EPA has proposed. Some initial thoughts on the proposed draft reporting form template include the following:

- One initial concern is that many companies do not allow the use of workbooks containing macros as a cybersecurity measure and the current draft workbook contains macros. If the form is dependent on the macro formatting, this may be an issue for some reporters using the form.
- We do not support the reporting of additional information related to well transfers (including name, phone number, email, and mailing address) as proposed §60.5420b(b)(1)(v).
- The control device and closed vent system tabs are set up where multiple affected facilities that route to a single control device or through the same closed vent system cannot be identified on a single row. This will result in redundant and duplicate information being reported.
- Certain selection options for "Deviation Category" the "Description of Deviation" and "Type of Deviation" cells are automatically blacked out and do not allow an operator to provide additional context. The operator should have the ability to add free text in these areas and provide additional information as needed.

We will continue to review the recordkeeping and reporting requirements proposed within these rules along with the draft reporting form (EPA-HQ-OAR-2021-0317-1536_content) and continue to provide EPA feedback on ways to streamline the template.

13.2.1 CEDRI System Concerns

Our members have concerns with the practical implications with reporting through CEDRI when/if there is a system outage. Specifically, we request EPA evaluate the following language as proposed under NSPS OOOOb and EG OOOOc, but note these concerns also apply to NSPS OOOOa:

- §60.5420b(e)(2): We believe this paragraph should be removed or, at a minimum, be inclusive of the compliance end period and the compliance submittal date. Staff scheduling submittal may choose to do so prior to 5 days before the compliance submittal date. If EPA is requiring the use of the reporting form within CEDRI, then it should not be in deviation on the operator in any circumstance.

- §60.5420b(e)(4): The requirement for the reporter to notify EPA immediately upon discovery of an outage is unduly burdensome for the reporter. EPA should manage the reporting system and notify registered users of an outage.

- §60.5420b(e)(5)(iii): It is unclear what EPA is intending for a reporter to include as far as "a description of measure taken to minimize the delay in reporting". EPA should be taking action to minimize the delay in reporting if there is a CEDRI system outage. The regulated entity has no additional recourse in this instance.

- §60.5420b(e)(6): System outage should warrant automatic claims to those submitting reports. Operators should not be penalized when the only method for submittal is not available and out of their control.
- EPA should implement a secure process, similar to EPA's e-GGRT program, to prevent those who are not owners or operators or are authorized representatives of an affected facility from submitting to CEDRI for any affected facility.

13.3 EPA should clarify its statements regarding the Crude Oil and Natural Gas source category and the extent of crude oil operations for purposes of this rulemaking.

Within proposed NSPS OOOOb and EG OOOOc the Crude Oil and Natural Gas source category is defined consistent with historical definitions finalized in NSPS OOOO and NSPS OOOOa:

> *Crude oil and natural gas source category means:*
>
> > *(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and*
> > *(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.*

In footnote 301 (87 FR 74833), EPA states:

> 301 *"For purposes of the November 2021 proposal and this supplemental proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.*

We do not believe that EPA intends to regulate crude oil operations beyond the point of custody transfer from a well to a transmission pipeline and we request that EPA clarify and correct these statements in the final rule to align with the definition of the source category as proposed.

13.4 Applicability for Inactive sites and Reactivation of Inactive Sites

Many sites may periodically shut-in or depressurize all or partial equipment, where the entire site might be inactive or certain equipment might be inactive. We believe this is an appropriate criterion for exemption for all affected or designated facilities under NSPS OOOOb and EG OOOOc. At a minimum, we seek clarification as the status of inactive facilities and depressurized equipment as they pertain specifically to fugitive emission monitoring (Comment 2.5) and the retrofit of pneumatic controller and pneumatic pump provisions under EG OOOOc. We do not believe it is EPA's intent to require facilities that are not in active operations to retrofit the pneumatic controllers at the facility to non-emitting nor would it be appropriate for equipment that has been depressurized and inactive to be screened for fugitive emission monitoring.

Additionally, some inactive sites or equipment might be put back into service, where the applicability under NSPS OOOOb versus EG OOOOc must be delineated. One example is under Pennsylvania's § 127.11a. Reactivation of sources, which allows: *"a source which has been out of operation or production for at least 1 year but less than or equal to 5 years may be reactivated and will not be considered a new source if the following conditions are satisfied…".* EPA already has included language addressing this concept as it pertains to storage vessels. We

believe EPA should extend this concept to all affected and designated facilities. If a site that was inactive were to become active, there should be adequate time for the site to comply with the provisions within EG OOOOc.

13.5 The Social Cost of Greenhouse Gases

API shares the Administration's goal of reducing economy wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the EPA's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

In Attachment B, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine provided to the IWG.

13.6 Cross Reference and other Minor Clarifications

Below are some cross reference and other typos we have identified within the prosed NSPS OOOOb and EG OOOOc regulatory text.

- Subpart OOOOc makes eight references to a §60.5933c, one of which gives its title as "Alternative Means of Emissions Limitation." However, there is no actual section in EG OOOOc with that number or title.
- §60.5413b(d)(11)(iii): *A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC and methane (if applicable) required under this subpart.*
- §60.5370b(a)(1)(iii) refers to §60.5385b(a)(3), which does not appear to exist.
- The additional citations should be checked for correct cross referencing: §60.5420b(c)(2)(ii)(B), §60.5410b(f)(2)(iv)(B), §60.5420b(b)(10)(vi), and §60.5420b(c)(12).

Attachment A

Responses to EPA Solicited Comments for Use of Optical Gas Imaging in Leak Detection

Responses to EPA Solicited Comments for Use of Optical Gas Imaging (OGI) in Leak Detection

VI.C OGI Monitoring Requirements – Specifying Dwell Time to Account for Scene Complexity

[T]he EPA is soliciting comment on how dwell time could be based on the scene while still accounting for the differences in the complexity of scenes or ways to create bins for “simple” and “complex” scenes.

Response: *The most intuitive method to differentiate between “simple” and “complex” scenes would be to base it on the number of components being imaged and viewing distance. An example of a “simple” scene would be a scene of 20-25 components viewed at a distance of < 15-25 feet. This approach offers a high probability of leak detection by a technician. The high probability of detection is supported by existing operating envelope testing conducted by camera manufacturers which demonstrated consistent image detection at these distances at delta-T as low as 2 degrees C. Moreover, the number of components being limited to 25 in a simple scene means a technician is likely to have great discernment or granularity of the image which improves their ability to detect image of a leak. “Complex” scenes would be when there are greater than 25 components or viewing distances greater than 25 feet.*

VI.C OGI Monitoring Requirements – Ensuring OGI Camera Operators Survey a Scene is Adequate Without Specifying Dwell Time

The EPA is also soliciting comment on ways to similarly achieve the goal of ensuring that OGI camera operators survey a scene for an adequate amount of time to ensure there are no leaks from any components in the field of view without specifying a dwell time.

Response: *The “simple” scene criteria offered previously ensures that a technician has optimum image detection consistent with operating envelopes of camera. Specifying a dwell time for these types of scenes would be irrelevant as the technician will be looking closely at the scene in their viewfinder looking to detect any imagery. Placing a constraint of dwell time would complicate their efforts and distract from their efforts at viewing the scene. A well-trained technician who consistently passes their performance audits will be expected to make a diligent and careful survey of the components in the scene.*

VI.C OGI Camera Operators – Performance Audit Frequency

The EPA believes that it is important to verify the performance of all OGI camera operators, even the most experienced operators, on an ongoing basis. Nevertheless, the EPA is requesting comment on whether there should be a reduced performance audit frequency for certain OGI camera operators, and if so, who should qualify for a reduced frequency, what the reduced frequency should be, and the basis for the reduced frequency.

Response: *The performance audit requirements can become a significant time-consuming activity for site(s) with large numbers of technicians in their survey crew. In the initial stages of OGI monitoring implementation, more frequent performance audits have a key role to play in ensuring technician efficacy. However, technician monitoring proficiency will increase quickly over time as their monitoring experience and time doing surveys increases. The*

agency's reference to the MTEC study clearly documented this to be the case. As such, for technicians who consistently have satisfactory performance audits, it is appropriate to extend the interval between audits for those technicians. A simple methodology to do so is to follow a "skip period" approach to performance audits. For technicians who pass four consecutive quarterly performance audits, then their audit interval should be extended to semi-annual. For technicians who pass two consecutive semi-annual performance audits, then their audit interval should be extended to annual. If a technician does not pass a semi-annual or annual audit or conduct a monitoring survey during the previous 12 months per Section 10.5 of Appendix K, then quarterly performance audits would be restarted.

VI.C OGI Surveys – Length of Survey Period

[T]he EPA has heard anecdotally that this may have more to do with the number of hours the OGI camera operator has surveyed during the day, such that it is more appropriate to limit the hours of surveying per day than it is to mandate rest breaks at a set frequency. The EPA is seeking any empirical data on the topic of the necessity of rest breaks when conducting OGI surveys or the link between operator performance and length of survey period.

***Response**: Fatigue potential is directly related to duration of continuous viewing through the camera and holding the camera in viewing position for extended periods. OSHA already has appropriate guidelines for ergonomics in the work place which include eye strain etc. Sites already have rigorous guidelines and safeguards for ergonomics, heat stress, etc. EPA should not attempt to develop regulatory standards for technician rest breaks. The agency should simply state that the monitoring plan incorporate appropriate rest breaks for technicians and simply state a rest break is required if the technician has been conducting a continuous viewing through OGI camera for 20 minutes or more. It is important to note that technicians would rarely have a 20-minute continuous viewing scenario. The primary monitoring method is to survey a component or scene for 1-2 minutes and then move to next location. When moving viewing locations, the technician would lower the camera to a neutral position and not be "viewing" though camera.*

VI.C Adequate Delta-T – OGI Camera

The EPA is proposing that the monitoring plan must describe how the operator will ensure an adequate delta-T is present to view potential gaseous emissions, e.g., using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view. […] [A] commenter stated guidance should be added for operators who are using a background temperature reading in the OGI camera field of view. The EPA is requesting comment on ways that an OGI camera operator can ensure an adequate delta-T exists during monitoring surveys for cameras that do not have a built-in delta-T check function.

***Response:** The simplest and most straightforward way for a technician to ensure adequate delta-T is to utilize the camera's function to display the temperature of the equipment or background behind the component being surveyed for leaks. Most, if not all, OGI cameras in use for leak surveys have this ability currently. As such, if the technician knows the ambient temperature, then it is a simple step to add/subtract the background from ambient to determine delta-T. The elegance of this approach is it allows the technician to adjust their angles or take additional steps in*

real-time during the survey process to ensure the delta-T of the operating envelope is maintained during any survey step.

VI.C Daily OGI Camera Demonstration Prior to Imaging to Determine Maximum Distance for Imaging

[O]ne commenter suggested that instead of having different operating envelopes for different situations and having to decide which envelope to use, the OGI camera operator should conduct a daily camera demonstration each day prior to imaging to determine the maximum distance at which the OGI camera operator should image for that day. The EPA believes that this type of determination would be more difficult and costly than creating an operating envelope, as it would require OGI camera operators to have necessary gas supplies on hand and take time to do this determination daily, or potentially multiple times a day. Nevertheless, the EPA is requesting comment on this suggestion, as well as how such a demonstration could be used if conditions on the site change throughout the day, at what point would the changed conditions necessitate repeating the demonstration, and how changes in the background in different areas of the site (such as to affect the delta-T) would be factored into such a demonstration.

Response: *Use of pre-defined operating envelopes through testing as prescribed in Section 8.0 of Appendix K is a highly useful and pragmatic methodology to determine detection capability and restrictions for monitoring surveys. It is expected that most OGI camera manufacturers plan to have completed the development of the operating envelopes after Appendix K is promulgated. However, the option for a site to do a daily or site-specific distance check utilizing a known gas concentration and flow rate at actual metrological conditions prior to conducting monitoring surveys should remain an option for a site.*

The reasons for retaining an option for a daily distance check are two-fold. First, a site may be conducting monitoring surveys with an OGI camera that does not yet have established operating envelopes. This could occur for a site using an OGI camera new to market or simply that initial monitoring surveys are planned to improve emissions reductions potential prior to the manufacturer publishing operating envelopes. Second, a site may believe that monitoring conditions for a given survey or site are unique with respect to pre-defined operating envelopes and want to ensure that the guidance on delta T and distance are appropriately set for the technicians' survey task. It is logical to include this option in Appendix K.

With respect to changing conditions, technicians should already be trained in recognition of factors (e.g., meteorological conditions) which would impact the leak detection capability. When conditions are significantly different then the technicians should switch to another operating envelope or conduct another distance check verification. This is already adequately addressed in Section 9.2.3. language.

Comments for Appendix K

"Appendix K. The EPA is not including a requirement to conduct OGI monitoring according to the proposed appendix K for well sites or centralized production facilities, as was proposed in the November 2021 proposal. Instead, the EPA is proposing to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21." [FR74723]

Comment: *This is the correct decision and recognizes the fundamental differences between upstream production and other industry sectors.*

Definition of fugitive emissions component. The EPA is proposing specific revisions to the definition of fugitive emissions component that was included in the November 2021 proposal. First, the EPA is proposing to add yard piping as one of the specifically enumerated components in the definition of a fugitive emissions component. While not common, pipes can experience cracks or holes, which can lead to fugitive emissions. The EPA is proposing to include yard piping in the definition of fugitive emissions component to ensure that when fugitive emissions are found from the pipe itself the necessary repairs are completed accordingly. [FR 74723]

Comment*: Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.*

Definition of fugitive emissions component. Based on changes made and discussed under section IV.A.1.a.ii of this preamble, the EPA is proposing to define fugitive emissions component as any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and CVS not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping. [FR 74736]

Comment*: The agency has consistently set VOC and VHAP content criteria in all previous fugitive emissions component monitoring requirements. These thresholds were typically defined as "in VOC service" which specified 10% VOC as the appropriate level where the emission reduction potential from leaking components was cost-beneficial. The agency stated that no data had been offered to support a one percent methane threshold and that produced water and wastewater streams can be significant sources of emissions. In the cited reference document ''Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations.'' Final Report. California Air Resources Board. May 2020, it stated that concentrations of compounds in the liquid phase were the best prediction of expected air emissions. This is correct and makes the point of industry comment to set a definitive threshold where cost beneficial emissions can be expected. Emissions potential is directly related to the concentration of methane and/or hydrocarbon in the process stream. Small concentrations of VOC (<10 wt%) and methane do not represent significant emissions potential; a fact that the agency has recognized in multiple updates to fugitive emission regulations.*

The apparent agency approach was simply to set the threshold at a single molecule which is inconsistent with decades of regulatory approaches to fugitive emission control methodology. As the relative proportion of VOC or methane in the given component goes down, the cost effectiveness of LDAR gets increasingly less favorable until, when the amount of VOC or methane approaches zero, the cost effectiveness value approaches infinity. The agency must consider cost for BSER determination. The content threshold used within the agency's cost effectiveness analysis is unclear. Either the agency used the traditional threshold content approach for estimating the potential regulated component inventory or it has overstated the cost effectiveness through the overstatement of emissions potential from components with very small methane and VOC contents.

In the preamble, the agency stated that industry had offered no empirical data to not establish an appropriate threshold. The agency has not demonstrated why a 1% methane and 10% VOC threshold are not appropriate, or how meaningful and cost-effective emission reductions are achieved at levels below those proposed by industry. This demonstration was not met by the agency in their definition of "potential to emit" and therefore the agency has not justified their decision. The recommendation to set the definition to include the VOC threshold at 10% and methane at 1% is an appropriate good faith effort by industry to reduce emissions.

EPA proposed that where a CVS is used to route emissions from an affected facility, the owner or operator would demonstrate there are no detectable emissions (NDE) from the covers and CVS through OGI or EPA Method 21 monitoring conducted during the fugitive emissions survey. Where emissions are detected, the emissions would be considered a violation of the NDE standard and thus a deviation. [FR 74804]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. These standards mandate that closed-vent systems are monitored annually with 5/15-day repair criteria. Routine AVO monitoring rounds by unit operators is also a standard work practice. CVS piping and components have been consistently found to have low leak percentages which makes sense when one considers that most of these components remained in a fixed configuration (i.e.., car-sealed open) and there is little to no operating changes of the FECs.*

The agency proposed action to make any emissions detection a violation is also a departure from historical leak detection and repair regulatory standards. EPA stated that their logic was that the NDE requirement was an emission standard and as such it has to be a violation even if repair provisions were allowed. This is an inappropriate regulatory approach since the NDE requirement should be considered a work practice standard rather than a numerical emissions standard. The CVS and control device requirements are sufficient to ensure that NDE operating conditions are the norm. The fact that the agency has prescribed monitoring survey requirements indicates the agency knows this paradigm to be true. The most important aspect of leak detection is routine surveillance of components and piping at appropriate intervals with prompt repair to stop the leak. The current 5-15 day repair timelines achieves this fundamental precept of LDAR, and making any leak detection a violation is an unnecessary addition to the requirements that does not expedite repairs or provide environmental benefits. Violations occur when repairs are not completed per requirements and/or routine monitoring is not conducted on-time or efficaciously.

In addition to this bimonthly OGI monitoring requirement, the EPA is also proposing to require OGI monitoring of each pressure relief device after each pressure release, as it is important to ensure the pressure relief device has reseated and is not allowing emissions to vent to the atmosphere. The EPA is soliciting comment on this change from a no detectable emissions standard to a bimonthly monitoring requirement. Where the EPA Method 21 option is used, we are proposing quarterly monitoring of the pressure relief device in addition of monitoring after each pressure relief. A leak is defined as an instrument reading of 500 ppm or greater when using EPA Method 21. [FR 74807]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. The most recent and stringent precedent for PRDs is found in the Part 63 Subpart CC which*

requires monitoring post-release to verify re-seating of PRD. The agency has consistently followed this approach in other RTR evaluations which makes this approach inconsistent with agency's technical analysis.

Not requiring routine monitoring of PRDs makes sense if one considers that if PRDs are properly seated then they are assumed to be in non-venting condition. Monitoring post-release is sufficient to ensure the emission standard is maintained.

EPA is proposing a requirement to monitor the CVS at the same frequency (i.e., bimonthly OGI in accordance with appendix K or quarterly EPA Method 21) as other equipment in the process unit and to repair any leaks identified during the routine monitoring. [FR 74808]

Comment: *In existing and recently revised NSPS and NESHAP standards for closed vent systems and control devices, the agency has prescribed initial inspection and on-going annual AVO inspections. The agency indicated there would be no cost to do these surveys, but that is incorrect. The monitoring survey routes would have to be expanded to include the CVS piping/ductwork sections which increases labor costs based on increased technician field survey time.*

Appendix K

EPA is proposing to revise the scope and applicability for appendix K to remove the sector applicability and to base the applicability on being able to image most of the compounds in the gaseous emissions from the process equipment. The EPA is retaining the requirement that appendix K does not on its own apply to anyone but must be referenced by a subpart before it would apply. [FR 74837] (App K VI.B.1)

1.3 Applicability. This protocol is applicable to facilities when specified in a referencing subpart. This protocol is intended to help determine the presence and location of leaks and is not currently applicable for use in direct emission rate measurements from sources

Comment: *This change in applicability is the correct approach. However, consistent with previously submitted comments on the proposed rulemaking, we recommend EPA proceed expeditiously to amend part 63 subpart CC (RMACT 1) to allow use of OGI technology and Appendix K as an alternative to Method 21 for refineries. In the recent Refinery Sector Rulemaking, EPA proposed allowing for use of OGI as an alternative to Method 21, but did not finalize that proposal because "we have not yet proposed appendix K."*[107] *Adding OGI as an alternative to RMACT 1 would significantly reduce the refinery and Agency resources associated with preparing and reviewing Alternative Method of Emission Limitation or Alternative Monitoring requests to allow OGI for those facilities and allow refineries to take advantage of the improvements inherent in Appendix K versus the currently available leak detection and repair (LDAR) Alternative Work Practice (AWP) in Part 60 Subpart A (§60.18(g), (h) and (i)). Moreover, it would be important for EPA to amend other Part 60 and 63 standards to make Appendix K an option for industry sectors beyond refineries.*

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[107] 80 *Fed. Reg.* 75191 (December 1, 2015)

6.1.2 The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr) and either butane emissions of 5.0 g/hr or propane emissions of 18 g/hr at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less, unless the referencing subpart provides detection rates for a different compound(s) for that subpart.

Comment: *The response factor for butane and propane are almost identical, why has the agency selected lower mass rate criteria for butane? It seems inconsistent with the language in Section 1.2 which allows for the average response factor approach with respect to propane.*

9.3 The site must conduct monitoring surveys using a methodology that ensures that all the components regulated by the referencing subpart within the unit or area are monitored. This must be achieved using one of the following three approaches or a combination of these approaches. The approach(es) chosen and how the approach(es) will be implemented must be described in the monitoring plan

Comment: *The language provided in the Appendix K revisions for monitoring survey methodology provides additional flexibility consistent with industry comments. However, as written, the methodology is limited to just three options without any ability for a site to propose an alternative. Technology and survey approaches are always being improved with new creative ideas coming to forefront all the time. For example, use of GPS in surveys is only a recent capability in the past few years. The agency should add language which allows a site to use another methodology as long as it meets the intent and capabilities of the ones currently identified. A site could propose an alternative to their delegated authority prior to use*

9.4.1 For a complex scene of components, the operator must divide the scene into manageable subsections and dwell on each angle for a minimum of 2 seconds per component in the field of view (e.g., for a subsection with 5 components, the minimum dwell time would be 10 seconds). It may be necessary to reduce distance or change angles in order to reduce the number of components in the field of view

Comment: *See comments provided on “simple” and “complex” scene approaches.*

9.7.2 A full video of the monitoring survey must be recorded. The video must document the monitoring results for each piece of regulated equipment. Leaking components must be tagged for repair, and the date, time, location of each leak, and identification of the component associated with each leak must be recorded and stored with the OGI survey records.

Comment *– This language could be read to imply a full continuous video of the monitoring survey would be required which is inconsistent with the language of Section 9.7.1 where only video or still imagery of the leaks are required. This language should be deleted or clearly state that sites may elect as alternative to simply save the full continuous video versus leak imagery only.*

9.8 The monitoring plan must include a quality assurance (QA) verification video for each OGI operator at least once each monitoring day. The QA verification video must be a minimum of 5 minutes long and document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration.

***Comment** – As mentioned in previous comments to Appendix K proposals, the daily QA verification video is unlikely to offer much value to a monitoring program. The most effective methodology to ensure technician monitoring efficacy is comparative monitoring via periodic performance audits. The daily quality assurance (QA) verification video requirement should be deleted.*

10.2.2.1 A minimum of 3 survey hours with OGI where trainees observe the techniques and methods of a senior OGI camera operator (see definition in Section 3.0) who reinforces the classroom training elements.

10.2.2.2 A minimum of 12 survey hours with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and providing instruction/correction where necessary.

10.2.2.3 A minimum of 15 survey hours with OGI where the trainee performs monitoring surveys independently with a senior OGI camera operator trainer present and the senior OGI camera operator providing oversight and instruction/correction to the trainee where necessary.

***Comment:** The specific hourly requirement for each survey training phase is too restrictive and does not reflect how individuals learn and master new skills. Some technicians may need more or less time in a particular phase or benefit more from side-by-side or direct observation. A more appropriate approach is to specify a total of 30 hours of field survey hours which includes direct observation, side-by-side, and independent surveys without such prescriptive hourly content. As long as the 30 hours of training surveys includes an appropriate number of components to be surveyed (e.g., 300) and a final monitoring survey test, then the proficiency will be attained and verified.*

Attachment B

Comments on the U.S. Environmental Protection Agency’s Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

I. INTRODUCTION

As an addendum to our comments on the U.S. Environmental Protection Agency's ("EPA's" or "the Agency's") Supplemental Notice of Proposed Rulemaking on the revised "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" ("Proposed NSPS Revision"),[108] the American Petroleum Institute ("API") respectfully submits these additional comments on EPA's "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances" ("SC-GHG Report").[109]

API represents all segments of America's oil and natural gas industry. Our over 600 members produce, process, and distribute the majority of the nation's energy. The industry supports millions of U.S. jobs and is backed by a growing grassroots movement of millions of Americans. API was formed in 1919 as a standards-setting organization. In our first 100 years, API has developed more than 700 standards to enhance operational and environmental safety, efficiency, and sustainability. API and its members are committed to delivering solutions that reduce the risks of climate change while meeting society's growing energy needs. Addressing this dual challenge requires new approaches, new partners, new policies, and continuous innovation.

API believes that the pace of global action to reduce greenhouse gas ("GHG") emissions and effectively mitigate climate change will be determined by government policies and technology innovation. To that end, we have laid out a Climate Action Framework[110] that presents actions we are taking to accelerate technology and innovation, further mitigate GHG emissions from operations, advance cleaner fuels, drive comparable and reliable climate reporting, and, importantly, endorse a carbon price policy.

The natural gas and oil industry is essential to supporting a modern standard of living for all by ensuring that communities have access to affordable, reliable, and cleaner energy, and we are committed to working with local communities and policymakers to promote these principles across the energy sector. Our top priority remains public health and safety, and companies often have well-established policies in place for proactive community engagement and feedback aimed at fostering a culture of trust, inclusivity, and transparency. We believe that all people should be treated fairly, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

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[108] 87 Fed. Reg. 74,702 (Dec. 6, 2022).

[109] Docket ID No. EPA-HQ-OAR-2021-0317 (Sept. 2022).

[110] https://www.api.org/climate.

Indeed, API has for many years attempted to constructively engage the IWG in its development of SC-GHG estimates, and has submitted detailed comments on multiple previous IWG technical support documents, including the IWG's most recent "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" ("Interim TSD").[111] Those comments provided the IWG constructive and actionable recommendations to improve the transparency, rationality, defensibility, and thus, durability of its estimates of the SC-GHG, and urged caution on the inherently limited utility of SC-GHG estimates. Those comments also specifically recommended that the IWG publish proposals for, and accept public comment on, the recommendations the IWG was required to provide by September 1, 2021 regarding potential applications for the SC-GHG,[112] the additional recommendations the IWG was required to provide by June 1, 2022 for revising the processes and methodologies for estimating the SC-GHG,[113] and final SC-GHG estimates the IWG was supposed to publish "no later than January 2022."[114]

Insofar as API is aware, after publishing the interim SC-GHG estimates in 2021, the IWG has not completed any of the actions required by E.O. 13990 or taken any action in response to comments and recommendations submitted by API and other parties. Moreover, notwithstanding that EPA is a key participant in the IWG, EPA's unilateral development of the revised SC-GHG estimates in the SC-GHG Report is not only inconsistent with the approach President Biden committed to in E.O. 13990, it does not appear to reflect any consideration of the comments API and others provided to the IWG.

In the detailed comments that follow, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine ("National Academies" or "NASEM") provided to the IWG.

Although API appreciates EPA's willingness to accept comments on the SC-GHG Report, consistent with the National Academies' recommendations, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each modules had been updated and the SC-GHG Report had been fully drafted. Given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is insufficient for soliciting detailed feedback from informed stakeholders, particularly given that this comment period encompassed multiple holidays.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. This is a particular concern in a rulemaking conducted pursuant

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[111] 86 Fed. Reg. 24,669 (May 7, 2021).
[112] *See* 86 Fed. Reg. at 24,670.
[113] *See* E.O. 13990 at Sec. (5)(b)(ii)(D) and (E).
[114] *See* E.O. 13990 at Sec. (5)(b)(ii)(B).

to the Clean Air Act ("CAA" or "the Act") because of the CAA's enhanced requirement that EPA justify rules based solely on the record it compiles and makes public at the time of the proposal.[115]

Notwithstanding the forgoing, in Section III.b. below, API raises a number of significant technical questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. As noted therein, it is critical the SC-GHG Report completely and transparently explain the precise basis for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Finally, in Section III.c, API describes why, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. As EPA seemingly recognizes based on its apparent intent to use the SC-GHG Report in the Regulatory Impact Analysis but not as part of its assessment of the Best System of Emissions Reduction ("BSER") in the Proposed NSPS Revision itself, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.[116]

II. BACKGROUND

As noted in EPA's SC-GHG Report, the SC-GHG represents "the monetary value of future stream of net damages associated with adding one ton of that GHG to the atmosphere in a given year."[117] This metric, which originally attempted to estimate the social cost of only CO_2 emissions, "was explicitly designed for agency use pursuant to E.O. 12866. . ."[118] Since it was signed by President Clinton in 1993, E.O. 12866 has directed agencies to "propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs."[119] And when the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). Thus, the SC-GHG Report characterizes the SC-GHG as "the theoretically appropriate value to use when conducting benefit-cost analyses of policies that affect GHG emissions,"[120] and consistent with that characterization, EPA purports to only rely on the SC-GHG Report in the RIA it issued in support of the Proposed NSPS Revisions.[121]

Initially, federal agencies' consideration of CO_2 emissions in RIAs was sporadic and varied significantly between agencies.[122] When agencies did consider CO_2 emissions, they utilized a variety of different methodologies that

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[115] *See Sierra Club v. Costle*, 657 F.2d 298, 401 (D.C. Cir. 1981).

[116] *See* 87 Fed. Reg. at 74,713.

[117] SC-GHG Report at 4.

[118] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428. Per E.O. 12866 Sec. 1(a): "Federal agencies should promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling public need, such as material failures of private markets to protect or improve the health and safety of the public, the environment, or the well-being of the American people. . . . Further, in choosing among alternative regulatory approaches, agencies should select those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach."

[119] E.O. 12866 at Sec. 1(a). When the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). (E.O. 12866 at Sec. 6(a)(3)(C)). A "Significant regulatory action" is "any regulatory action that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in [E.O. 12866]" (Sec. 3(f)).

[120] SC-GHG Report at 4.

[121] *See* 87 Fed. Reg. at 74,713.

[122] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

resulted in a wide range of estimates, each with different ranges of uncertainty.[123] The government was consistent, however, in limiting use of these early estimates to RIAs, and in providing separate values for "domestic" and "global" impacts.[124] The government's consideration of CO_2 emissions became more frequent and consistent, however, after a 2008 Ninth Circuit decision remanded a fuel economy rule for failing to consider the potential benefit of CO_2 emission reductions, stating that "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero."[125] Subsequent court decisions on the necessity and method of considering CO_2 emissions for federal agency actions have been mixed.

To help federal agencies comply with E.O. 12866, "harmonize a range of different SC-CO_2 values being used across multiple Federal agencies,"[126] and "ensure consistency in how benefits are evaluated across agencies," President Obama established the IWG in 2009.[127] The IWG was tasked with developing "a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions."[128] As such, from the beginning, the IWG's SC-GHG estimates were intended to provide consistency across federal government agencies exclusively for the development of RIAs for "significant regulatory actions" involving GHG emissions. Notably, [t]his does not apply to many routine agency actions that will produce GHG emissions."[129]

The IWG's November 2013 TSD represented the first time the IWG (through OMB) accepted comment on the SC-CO_2 estimates.[130] Although the IWG and OMB had finally agreed to accept comments, they did not provide any materials other than the most recent TSDs. Thus, comments submitted by API and others urged the IWG to select its Integrated Assessment Model ("IAM") parameters through a highly transparent, collaborative, and data-driven process because modest changes to just a few model inputs drastically changes the output of the IAMs and therefore the SC-CO_2 estimate.[131]

The IWG broadly responded to the comments it received on the 2013 TSD in July 2015.[132] In that response, the IWG reiterated that the "purpose of [the IWG's] process was to ensure that agencies were using the best available information and to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions, or costs from increasing emissions, in regulatory impact analyses."[133]

The IWG updated its estimates of the SC-CO_2 again in August of 2016[134], and while API and others continued to have concerns with the transparency and rigor with which the IWG selected its model inputs, the TSD for the 2016 SC-CO_2 reflected some improvement to the characterization of uncertainty that was consistent with the NASEM Phase

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[123] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[124] Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (February 2020) ("2010 TSD) at 3.

[125] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1200 (9th Cir. 2008).

[126] 2021 TSD at 10.

[127] 2010 TSD at 4.

[128] 2010 TSD at 5.

[129] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[130] OMB's first-ever solicitation of public comment on the SC-CO_2 estimates was likely in response to a September 4, 2013 multi-association Petition for Correction filed under the Information Quality Act ("IQA") and numerous demands from Congress and other stakeholders for increasing the transparency of the SC-CO_2 estimation process.

[131] *See* multi-association comments filed February 26, 2014 (OMB-2013-0007-0140). OMB's July 2015 Response to Comments did not provide the key information sought by API and others, and resisted recommendations that the IWG select these parameters through a transparent process subject to peer review. (*See* July 2015 Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.) To its credit, however, OMB requested feedback from the NASEM on the IWG's process for updating the estimates of the SC-CO_2. (*See* NASEM 2017 at 1).

[132] Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (July 2015) ("2015 RTC").

[133] 2015 RTC at 3.

[134] 2016a TSD.

1 Report,[135] as well as API's prior comments. Notably, in an addendum to the 2016 TSD, the IWG adapted its SC-CO_2 methodology to estimate social costs for methane and nitrous oxide for the first time.[136] While the 2016 TSD represented the first time the IWG provided estimates of non-CO_2 GHG emissions, the IWG continued to represent that the purpose of the estimates was to allow agencies to consistently "incorporate the social benefits of reducing . . . emissions into cost-benefit analyses of regulatory actions."[137]

Months later, President Trump disbanded the IWG and instead directed each agency to develop their own SC-GHG estimates using the same IAMs and the IWG's same overall methodology for estimating the SC-GHGs.[138] As the U.S. Department of Justice explained in its June 4, 2021 brief in opposition to several states' motion to preliminarily enjoin Section 5 of E.O. 13990, and the interim SC-GHG values published under E.O. 13990:

> Although the Trump Administration's policy approach to climate issues differed in many ways from that of the preceding administration, it continued to use standardized estimates of the social costs of greenhouse gases. Pursuant to E.O. 13783, EPA developed interim SC-CO_2 estimates by making two (*and only two*) changes to the Working Group's 2016 estimates: First, it began reporting estimates that attempted to capture only the domestic impacts of climate change, and second, it applied 3% and 7% discount rates. . . . Accordingly, although the Working Group had been disbanded, and although the estimates of the social costs of greenhouse gas estimates were now lower (because of higher discount rates and an exclusive focus on U.S.-domestic damages), agencies continued to estimate the social costs of greenhouse gases in their cost-benefit analyses, as ordered by the President, just as they had done in prior administrations.[139]

While these two changes[140] were seemingly modest, their impact on the SC-GHG estimates, was anything but small. When the Obama Administration conducted its RIA for the Clean Power Plan ("CPP") in 2015, it estimated social costs of $12, $40, $60, and $120 per short ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 in 2011 dollars.[141] When the Trump Administration conducted its RIA for the review of the CPP in 2017, it estimated the SC-CO_2 to be $6 per metric ton in 2020 (also in 2011 dollars) at the 3% discount rate, and $1 at the 7% rate.[142]

> Thus, in the span of just two years, the same government agency, utilizing the 'best available science' put forth estimates for the same metric that had changed by so many orders of magnitude

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[135] National Academies of Sciences, Engineering, and Medicine 2016. *Valuing Climate Damages. Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on Near-Term Update*:. Washington, DC: The National Academies Press ("NASEM 2016").

[136] Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social cost of Methane and the Social Cost of Nitrous Oxide ("2016b TSD"). OMB did not request or receive the NASEM's feedback on the new estimates of the social costs of methane and nitrous oxide, nor were they subject to notice and comment, or peer reviewed. Rather, they were premised entirely on a U.S. Environmental Protection Agency ("EPA") employee's 2015 paper, which at that point had not been reviewed or published. (*See* Martin, A.L., Kopits, E.A., Griffiths, C.W., Newbold, S.C., and A Wolverton. 2015. Incremental CH_4 and N_2O Mitigation Benefits Consistent with the U.S. Government's SC-CO_2 Estimates. *Climate Policy* 15(2): 272-298).

[137] 2016 TSD at 3.

[138] *See* Executive Order 13783 (March 28, 2017) ("E.O. 13783").[138]

[139] *Missouri v. Biden*, 4:41-cv-00287 (E.D. MO 2021) (Page 11 of Defendants' June 4, 2021 Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction) (emphasis added).

[140] These changes flowed from E.O. 13783 ("when monetizing the value of changes in greenhouse gas emissions resulting from regulations, including with respect to the consideration of domestic versus international impacts and the consideration of appropriate agencies shall ensure, to the extent permitted by law, that any such estimates are consistent with the guidance contained in OMB Circular A-4.")

[141] U.S. EPA, EPA-452/R-15-03 Regulatory Impact Analysis for the Clean Power Plan (2015) at 4-2. (The four SC-CO2 estimates differ based on use of discount rates of 5%, 3%, 2.5%, and the ninety-fifth percentile distribution at the 3% discount rate. (See 4-6, 4-7).

[142] U.S. EPA, Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal (2017) at 44. The conversion factor for metric ton to short ton is approximately 0.91, such that these estimates were actually about 9% lower when compared to the Obama-era estimates (2017 CPP RIA at 44).

> as to be farcical. This was the case even though the Trump and Obama analyses utilized the same underlying models.[143]

Just a few years later, the IWG has republished the prior 2016 SC-GHG values as the new Interim SC-GHG estimates, and as instructed by E.O. 13990, these estimates "tak[e] global damages into account" and utilize discount rates that the IWG believes "reflect the interests of future generations in avoiding threats posed by climate change."[144] As a result, the Trump Administration's estimated SC-CO_2 values of $1 and $6 per metric ton in 2020 (in 2011 dollars)[145] increased to $14, $51, $76, and $152 per metric ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 (in 2020 dollars).[146]

This whipsawing of SC-GHG estimates is not based on any objective errors or omissions. Indeed, the IWG and Trump Administration can both point to academic scholarship and regulatory guidance in support of their selections of discount rates and geographic scales. Rather, these divergent estimates demonstrate the extent to which any given estimate of the SC-GHG differs based on one or two subjective judgements. The output of the models is dependent on subjective framing decisions that "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[147] And because many of the key analytical framing decisions that truly drove model output are subjective and not purely scientific determinations, robust and transparent stakeholder and public engagement is essential.

As API urged in its comments on the 2021 TSD and reiterates here, the sensitivity of SC-GHG modeling output to one or a few subjective inputs raises serious questions of the SC-GHG estimates' reliability and utility in rulemaking and policy analyses. It also illustrates the profound importance of adopting analytical framing decisions through a structured and predictable process that is open, transparent, and data-driven. While EPA may have valid reasons for unilaterally developing its own SC-GHG estimates, API is concerned that this unexplained deviation from the SC-GHG estimation and updating process that was historically consigned and recently re-entrusted to the IWG reflects another *ad hoc* estimation approach that lacks the necessary structure, consistency, and transparency.

Moreover, given that EPA's SC-GHG Report contains the most recent estimate of the SC-GHG provided by the federal government, API is concerned that other federal agencies may opt to rely on the estimates in the EPA's SC-GHG Report rather than the estimates in the IWG's 2021 Interim TSD. While this concern is somewhat mitigated by E.O. 13990's requirement that agencies use the IWG's values, the absence of any clear statement from EPA as to what the SC-GHG Report is or how its estimates are to be used perpetuates a serious concern that EPA's values may be misapplied in a variety of different regulatory and administrative contexts.

III. DETAILED COMMENTS

API is concerned about the procedures EPA employed when developing the SC-GHG Report and the revised estimates contained therein. We also have substantive technical questions and concerns about the methodology EPA employed in generating the revised SC-GHG estimates and the manner in which the Agency presented its

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[143] Taylor, A. (2018). Why the social cost of carbon is red herring. Tulane Environmental Law Journal, 31(2), 345-372 at 347.

[144] E.O. 13990 at Sec. 5(a) and 5(b)(iii).

[145] Using discount rates of 7% and 3%.

[146] Interim TSD at Table ES-1 (using discount rates of 5%, 3%, 2.5%, and the 95th percentile of the 3% discount rate)

[147] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 370. [T]hose who would consider inclusion of IAM-generated estimates, particularly high-dollar ones, of the SCC to be an unmitigated success should nonetheless pay heed to the crow on the shoulder: a high degree of arbitrariness is currently baked into these estimates and it is quite difficult to know the degree to which they may be relied upon for accuracy or manipulated by agencies across different administrations.

estimates in the SC-GHG Report. Finally, API believes that EPA should more fully and explicitly explain why the inherent limits of the SC-GHG estimates render them unsuitable for agency rulemaking and decisions that require the SC-GHG to be expressed as a single value or within a reasonably narrow range of uncertainty. The subsections that follow discuss each of these three broad areas of concern in detail.

a. Procedural Concerns

As President Biden noted in Executive Order 13990 ("E.O. 13990") on his first day in office, "[a]n accurate social cost is essential for agencies to accurately determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses . . ."[148] To that end, E.O. 13990 further instructed that, in undertaking actions such as developing SC-GHG estimates, "the Federal Government must be guided by the best science and be protected by processes that ensure the integrity of Federal decision-making.[149] Consistent with that mandate, President Biden also issued a Presidential Memorandum to all heads of executive departments and agencies reaffirming the Biden Administration's commitment to the principles outlined in President Clinton's Executive Order 12866 ("E.O. 12866")[150], which established the basic foundation for executive branch review of regulations, and President Obama's Executive Order 13563 ("E.O. 13563"),[151] which "took important steps toward modernizing the regulatory review process."[152]

Thus, through the Regulatory Review Memorandum, President Biden reaffirmed his administration's commitment to "allow for public participation and an open exchange of ideas;"[153] using "best available techniques to quantify anticipated present and future benefits and costs as accurately as possible;"[154] and ensuring "the objectivity of any scientific and technological information and processes used to support . . . regulatory actions."[155]

One week later, President Biden reiterated to his executive departments and agency heads that "[i]t is the policy of my Administration to make evidence-based decisions guided by the best available science and data."[156] According to the President Biden's Scientific Integrity Memorandum, "[w]hen scientific or technological information is considered in policy decisions, it should be subjected to well-established scientific processes, including peer review where feasible and appropriate. . ."[157]

API supports the principles President Biden outlined in these Executive Orders and presidential memoranda, and believes that certain aspects of EPA's development of SC-GHG estimates, such as taking public comment and committing to peer review, are broadly consistent with these principles. In other respects, however, EPA's development of the SC-GHG Report thus far appears to be the product of an insufficiently structured and transparent process.

Indeed, EPA's SC-GHG Report represents an unexplained departure from the more structured, transparent, and collaborative interagency process that the Biden Administration promised when it encouraged stakeholders

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[148] E.O. 13990 at Sec. 5.
[149] E.O. 13990 at Sec. 1.
[150] Signed Sept. 30, 1993.
[151] Signed Jan. 18, 2011.
[152] Memorandum for the Heads of Executive Departments and Agencies regarding "Modernizing Regulatory Review" (Jan. 20, 2021) ("Regulatory Review Memorandum").
[153] E.O. 13563 at Sec. 1(a).
[154] E.O. 13563 at Sec. 1(c).
[155] E.O. 13563 at Sec. 5.
[156] "Memorandum on Restoring Trust in Government Through Scientific Integrity and Evidence-Based Policymaking" Memorandum From President Biden to the Heads of Executive Departments and Agencies (Jan. 27, 2021) ("Scientific Integrity Memorandum"). *See also* Executive Order 14007, which establishes the President's Council of Advisors on Science and Technology. (Jan. 27, 2021) ("E.O. 14007).
[157] Scientific Integrity Memorandum preamble.

interested in the SC-GHG development process to engage with the IWG. EPA's SC-GHG Report reflects no consideration of the comments API and others submitted to the IWG, and the limited data and time that EPA has provided at this stage does not appear consistent with a strong Agency interest in soliciting critical analysis. Furthermore, EPA's curious solicitation of comments on the SC-GHG Report within an NSPS rulemaking, which does not utilize the SC-GHG Report, does not particularly reflect an interest in transparency and collaboration. In fact, EPA's equivocal and fluctuating descriptions of the SC-GHG Report make it impossible for the public to even understand why EPA drafted the SC-GHG Report in the first place, or how the Agency intends to use it.

1. Lack of Clarity Regarding What the SC-GHG Report is and how it will be used

In both the preamble to the Proposed NSPS Revisions and the RIA in EPA's docket for the Proposed RIA Revisions ("Docketed RIA"), EPA concludes that the IWG's "interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science."[158] Therefore, the Agency "estimated the climate benefits of methane emission reductions expected from this proposed rule using the social cost of methane (SC-CH_4) estimates presented in the [IWG's 2021 TSD]."[159]

Having disclaimed that the RIA estimated the climate benefits of the proposal's anticipated methane reductions using only the interim SC-GHG estimates from the IWG's 2021 TSD, EPA's preamble to the Proposed NSPS Revisions then describes the SC-GHG Report as "a sensitivity analysis of the monetized climate benefits using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine."[160] According to EPA's preamble, the RIA presents the results of the SC-GHG Report's screening analysis in "Appendix B of the RIA."[161] However, the Docketed RIA does not include the sensitivity analysis EPA described in the preamble, nor does it contain any reference to, or even mention of, the SC-GHG Report.

Earlier versions of the RIA that were exchanged between and edited by EPA, OMB, and other agencies reflect that the RIA previously contained a substantial discussion of the SC-GHG Report and also included EPA's new estimates from the SC-GHG Report in a sensitivity analysis in a then-designated Appendix B.[162] These aspects of the draft RIA were deleted in their entirety without explanation shortly before publication of the Proposed NSPS Revisions. However, and particularly problematic from the perspective of transparency in public engagement as well as EPA's docket and rulemaking requirements under CAA Section 307, the version of the RIA that EPA posted on its website for public comment on November 11, 2022 contains the subsequently deleted discussion of the SC-GHG Report and Appendix B sensitivity analysis.[163] Thus, EPA is presently soliciting comments on two strikingly different versions of the Draft RIA. Indeed, while it is beyond the scope of this appendix's specific focus on EPA's SC-GHG Report, the Agency's publication of two divergent Draft RIAs raises significant questions about the sufficiency of the notice-and-comment opportunity on the required E.O. 12866 analysis as well as the Proposed NSPS Revisions.

While EPA's last minute revisions to the RIA remain unexplained, what is clear from the Docketed RIA is that EPA's SC-GHG Report is not a sensitivity analysis, and that the report's revised SC-GHG estimates are not amenable for use in sensitivity analyses. EPA's "Sensitivity and Uncertainty Analyses: Training Module" describes a "sensitivity analysis" as "a method to determine which variables, parameters, or other inputs have the most influence on the

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[158] 87 Fed. Reg. at 74,843; Docketed RIA (EPA-HQ-OAR-2021-0317-0173) at 3-6.

[159] 87 Fed. Reg. at 74,713; *See also* 87 Fed. Reg. at 74,843; *See also* the RIA in EPA's docket for the Proposed NSPS Revisions at 3-6.

[160] 87 Fed. Reg. at 74,843.

[161] 87 Fed. Reg. at 74,714, Table 5, note b; *See also* 87 Fed. Reg. at 74,843.

[162] *See* Draft RIA revisions between September and November 2021 at EPA-HQ-OAR-2021-0317-1540,1541, 1542, 1543, 1544, 1545, 1546, 1548, 1573, 1574, 1575, and 1576.

[163] *See* https://www.epa.gov/environmental-economics/scghg.

model output."[164] Consistent with this description, EPA's Training Module explains that "[t]here can be two purposes for conducting a sensitivity analysis [1] comput[ing] the effect of changes in model inputs on the outputs; [2] to study how uncertainty in a model output can be systematically apportioned to different sources of uncertainty in the model input."[165]

EPA's SC-GHG Report and the SC-GHG estimates contained therein are in no way suited to these purposes. The estimates in EPA's SC-GHG Report were derived in a manner wholly different from the IWG's SC-GHG estimates. For each of the four modules of the SC-GHG estimation process - socioeconomics and emissions, climate, damages, and discounting – EPA's SC-GHG Report uses different models, methodologies, analytical framing decisions, and data than the IWG utilized. As detailed in the Executive Summary to the SC-GHG Report:

> The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future Social Cost of Carbon Initiative . . . The climate module relies on the Finite Amplitude Impulse Response (FaIR) model… The socioeconomic projections and outputs of the climate module are used as inputs to the damage module to estimate monetized future damages from temperature changes. Based on a review of available studies and approaches to damage function estimation, the report uses three separate damage functions to form the damage module. They are: 1. a subnational-scale, sectoral damage function… 2. a country-scale, sectoral damage function… and 3. a meta-analysis-based damage function… The discounting module . . . us[es] a set of dynamic discount rates that have been calibrated following the Newell et al. (2022) approach, as applied in Rennert et al. (2022a, 2022b). … Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates. … Finally, the value of aversion to risk associated with damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. The estimation process generates nine separate distributions of estimates – the product of using three damage modules and three near-term target discount rates – of the social cost of each gas in each emissions year. To produce a range of estimates that reflects the uncertainty in the estimation exercise while providing a manageable number of estimates for policy analysis, in this report the multiple lines of evidence on damage modules are combined by averaging the results across the three damage module specifications.[166]

Every aspect of the above-described estimation process differs from the process employed by the IWG. And, because every aspect of EPA's SC-GHG estimation process differed from the IWG's process, it does not allow EPA "to determine which variables, parameters, or other inputs" in the IWG's estimation process "have the most influence on the model output." Examining two wholly different estimation processes does not provide any basis to discern how any of the IWG's inputs may impact the IWG's model output or apportion uncertainty to the IWG's various inputs.

"Sensitivity analyses" require the isolation and examination of one or a few model inputs while all other model parameters remain constant. For instance, in the 2021 TSD, the IWG advised that "agencies may consider

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[164] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).

[165] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).

[166] SC-GHG Report at 1-2.

conducting additional sensitivity analysis using discount rates below 2.5 percent."[167] Consistent with EPA's Training Module and standard practices for conducting sensitivity analyses, the IWG instructed that agencies' sensitivity analyses should isolate a single input (the discount rate) in order to assess the impact of changes from that single input on the model output.

The estimates in EPA's SC-GHG Report are simply new estimates based on new methods and data, and they therefore plainly have no value in any scientifically relevant sensitivity analysis. Indeed, what EPA deemed a "Screening Analysis" in the since-deleted sections of the Docketed RIA was not a screening analysis at all, at least as defined by EPA's Training Module. EPA merely compared the values from the IWG's 2021 TSD to EPA's SC-GHG Report and found that the benefits estimated in EPA's SC-GHG Report were higher than the IWG's 2021 interim estimates. This is truly the full extent of EPA's use of the SC-GHG Report for a "sensitivity analysis," which perhaps explains the Agency's decision to strike those references from the Docketed RIA.

Recognizing that neither EPA's SC-GHG Report nor the estimates contained therein constitute, or can credibly be used in sensitivity analyses, one is compelled to recognize the SC-GHG Report's estimates for what they are – SC-GHG values that are wholly separate and distinct from the 2021 IWG interim SC-GHG estimates that the Biden Administration directed all agencies to use. In fact, the SC-GHG Report itself never suggests its estimates are intended or even suitable for sensitivity analyses. The SC-GHG Report accurately describes them as "new estimates of the SC-GHG."[168]

Indeed, the SC-GHG Report's estimates are "new estimates of the SC-GHG," but given EPA's deletion of the supposed "sensitivity analysis" and assertion that the SC-GHG Report's estimates were not used in the RIA or the "statutory [best system of emissions reduction] determinations" in the Proposed NSPS Revisions,[169] commenters are left with no explanation why EPA developed the SC-GHG Report, how EPA intends to use the report's estimates, or why EPA included the SC-GHG Report in the docket for the Proposed NSPS Revisions. A truly transparent and collaborative process demands much more than this. EPA should provide a full and complete explanation for the development and intended use of the SC-GHG Report before subjecting it to peer review or public comment. Absent any explanation of the SC-GHG Report's intended use, reviewers have little basis to opine on its suitability.

2. <u>Inconsistency with the Biden Administration's Stated Approach to the SC-GHG</u>

From the earliest days of his Administration and consistently thereafter, President Biden and other Administration officials publicly committed to developing and updating government-wide SC-GHG estimates through the IWG by prescribing a detailed and incremental process. Based on the Administration's representations, API and other stakeholders devoted significant time and resources attempting to engage the IWG, but the rigorous and transparent IWG process that the Biden Administration promised has not yet materialized in any meaningful way. Now, more than two years after the IWG released its first and only publication of the several it had been charged with developing, EPA appears to be charting its own course by developing its own agency-specific SC-GHG estimates in the SC-GHG Report.

As discussed in more detail below, EPA's independent development of SC-GHG estimates is incompatible with and, in fact, undermines the unified approach promised by the Biden Administration in E.O 13990. We also describe

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[167] 2021 TSD at 4; *See also* 2021 TSD at 21 ("the IWG finds it appropriate as an interim recommendation that agencies may consider conducting additional sensitivity analysis using discount rates below 2.5%.").
[168] SC-GHG Report at 84.
[169] 87 Fed. Reg. at 74,843.

why EPA's unilateral SC-GHG estimates and any subsequent proliferation of agency-specific SC-GHG estimates contravene the Administration's stated interest in assessing the benefits and costs of proposed regulations consistently and cohesively across all federal agencies.

i. President Biden's Promised Approach for the Development and Agency use of SC-GHG Estimates

After the Trump Administration disbanded the IWG, President Biden on his first day in office issued E.O. 13990, which reestablished the IWG as the federal entity charged with developing and publishing the SC-GHG estimates that are to be used by all federal agencies.[170] The IWG's mission is fivefold:

> (A) publish an interim [SC-GHG] within 30 days of the date of this order, which agencies shall use when monetizing the value of changes in greenhouse gas emissions resulting from regulations and other relevant agency actions until final values are published;
>
> (B) publish a final [SC-GHG] by no later than January 2022;
>
> (C) provide recommendations to the President, by no later than September 1, 2021, regarding areas of decision-making, budgeting, and procurement by the Federal Government where the [SC-GHG] should be applied;
>
> (D) provide recommendations, by no later than June 1, 2022, regarding process for reviewing, and, as appropriate, updating, the [SC-GHG] to ensure that these costs are based on the best available economics and science; and
>
> (E) provide recommendations, to be published with the final [SC-GHG] under subparagraph (A) if feasible, and in any event by no later than June 1, 2022, to revise methodologies for calculating the [SC-GHG], to the extent that current methodologies do not adequately take account of climate risk, environmental justice, and intergenerational equity.[171]

Insofar as API is aware, the IWG has only completed the first of the five tasks prescribed by E.O. 13990.[172] Regarding these interim estimates, the E.O. mandates that "agencies ***shall*** use" them in promulgating their own "regulations and other relevant agency actions until final values are published."[173] Thus, although it is unclear why EPA developed the SC-GHG Report and how the Agency intends its SC-GHG estimates to be used, it bears mentioning that agencies deviating from these interim estimates do so in contravention with E.O. 13990.

The requirements of E.O. 13990 are also memorialized in the 2021 Interim TSD, which describes President Biden's directive that the reconstituted IWG "ensure that SC-GHG estimates used by the U.S. Government (USG) reflect the best available science and the recommendations of the National Academies (2017)…"[174] Consistent with the Executive Order, the IWG plainly recognized that the SC-GHG estimates it developed were to be used throughout the "U.S. Government," unless expressly precluded by statute.[175]

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[170] E.O. 13990 at Sec. 5.

[171] E.O. 13990 at Sec. 5(b)(ii).

[172] 2021 TSD.

[173] E.O. 13990 at Sec. 5(b)(ii)(a) (emphasis added).

[174] 2021 TSD at 3.

[175] Social Cost of Greenhouse Gas Emissions: Frequently Asked Questions (FAQs), ("OIRA Guidance") at 2, June 3, 2021. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/Social-Cost-of-Greenhouse-Gas-Emissions.pdf.

The IWG's Interim TSD goes on to instruct that the Interim SC-GHG estimates "should be used by agencies until a comprehensive review and update is developed in line with the requirements in E.O. 13990."[176] The Interim TSD also "determined that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates (2.5 percent, 3 percent, and 5 percent) as were used in regulatory analyses between 2010 and 2016 and subject to public comment."[177]

OMB, the entity responsible for coordinating the IWG efforts,[178] has likewise confirmed that President Biden's reconstitution of the IWG demonstrates that the President intended the IWG alone develop the SC-GHG estimates necessary "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[179] This directive is further confirmed in the June 2021 guidance document OIRA issued to agencies to assist in applying Section 5 of E.O. 13990.[180] The OIRA Guidance clarified that "[p]ursuant to E.O. 13990, when agencies prepare an assessment of the potential costs and benefits of regulatory action for purposes of compliance with E.O. 12866, they *must* use the 2021 interim estimates in monetizing increases or decreases in greenhouse gas emissions that result from regulations and other agency actions until updated values are released by the IWG."[181] Accordingly, E.O. 13990, the 2021 Interim TSD, OMB's solicitation of comments on the Interim TSD, and OIRA's guidance not only directed federal agencies to use the IWG's SC-GHG estimates, they apprised stakeholders interested in the federal government's SC-GHG estimates that the IWG was the sole entity with which to engage regarding the development of these important values.

In litigation surrounding E.O. 13990 and the 2021 Interim TSD, the U.S. Department of Justice ("DOJ") also describes the Biden Administration's stated approach to developing and using SC-GHG estimates, and opined on the degree to which E.O. 13990 compelled agencies to use the IWG's values:

> … the Executive Order requires agencies to use the Interim Estimates in some circumstances. *See* E.O. 13990 §§ 5(b)(ii)(A) (using the word "shall"); OIRA Guidance, at 1. But that directive is inoperative whenever the agency faces any conflicting statutory obligation . . .In other words, agencies will only ever rely on the Interim Estimates when they have discretion to do so…[182]

As DOJ stated elsewhere even more succinctly, "if an agency undertakes [SC-GHG] monetization, it shall use the Interim Estimates rather than another set of figures."[183]

ii. EPA's SC-GHG Report Contravenes the Approach President Biden Promised Stakeholders

Although it is not yet clear how EPA intends to use the estimates in its SC-GHG Report, the Agency's development and publication of these values appears to conflict with President Biden's explicit directive that the IWG develop the federal government's SC-GHG estimates and that federal agencies use those estimates. The Administration assigned this centralized role to the IWG "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[184] Even though EPA is a key member of the IWG and EPA's staff certainly

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[176] 2021 TSD at 4.
[177] 2021 TSD at 4.
[178] *See* E.O. 13990 at Sec. 5; *See also* 86 Fed. Reg. at 24,669.
[179] 86 Fed. Reg. at 24,669.
[180] *See* OIRA Guidance.
[181] OIRA Guidance at 1.
[182] Defendants' Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction, Page 23, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).
[183] Brief for Appellees, Page 40, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).
[184] 86 Fed. Reg. at 24,669.

have a high level of expertise in climate science and economic analysis, E.O. 13990's reestablishment of the IWG seems to indicate that the Biden Administration believed that development of the highly important SC-GHG estimates called for a breadth of expertise and diversity of opinions unlikely to be found within a single agency.

While API has often disagreed with the IWG's lack of transparency and with various modeling decisions and methodologies that the IWG has employed in developing SC-GHG estimates, we believe that the multi-agency composition of the IWG provides at least an opportunity to develop future SC-GHG estimates using a greater diversity of viewpoints and expertise. Thus, when the Biden Administration once again consigned the federal government's SC-GHG estimation process to the IWG, API once again devoted significant time and resources developing comments reflecting our own viewpoints and considerable expertise. Unfortunately, the IWG's unexplained inaction on the tasks it was assigned in E.O. 13990 along with EPA's unilateral development of SC-GHG estimates in contravention with E.O. 13990 seem to indicate that API's efforts to engage the IWG may have been in vain and that the process laid out in E.O. 13990 has been inexplicably abandoned.

API and others with a deep interest in, and credible expertise relevant to, the development of SC-GHG estimates are effectively precluded from meaningfully engaging with the federal government on these estimates if the Administration changes without explanation the entities, planned actions, and procedures for developing SC-GHG estimates.

The other reason the Administration re-established the IWG and tasked it with developing the SC-GHG estimates was "to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions in regulatory impact analyses."[185] This accords with OMB Circular A-4, which emphasizes that "[i]n undertaking [benefit-cost analysis and cost-effectiveness analysis], it is important to keep in mind the larger objective of analytical consistency in estimating benefits and costs *across regulations and agencies*, subject to statutory limitations."[186]

While we recognize that the Administration has announced its intent to revise Circular A-4,[187] the mere prospect of these revisions provides no basis for contravening the guidelines and instructions currently provided by Circular A-4. Unless and until Circular A-4 is revised or replaced, it should continue to guide EPA and other agencies to develop clear, transparently supported, objective, and consistent RIAs. Indeed, far from justifying any departures from Circular A-4's guidelines, the Administration's announcement that Circular A-4 will be revised further illustrates that EPA's unilateral development of SC-GHG estimates is inconsistent with the overall RIA and SC-GHG development framework that the Biden Administration publicly announced.

Finally, the need for a single consistent process for developing the SC-GHG estimates used in RIAs is further reflected in a 2020 Government Accountability Office ("GAO") Report on the SC-GHG and specifically the manner in which the federal government should address the recommendations of the National Academies."[188] Recognizing that the National Academies' recommended procedural and technical improvements could not be feasibly implemented by a multitude of different agencies, the GAO urged OMB to "identify a federal entity or entities to be responsible for addressing the National Academies' recommendations…"[189] GAO considered the recommendation "implemented" when E.O. 13990 reinstated the IWG.[190]

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[185] 2021 TSD at 10.

[186] OMB Circular A-4, Pages 9-10 (emphasis added).

[187] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.

[188] GAO-20-254, Report to Congressional Requesters, SOCIAL COST OF CARBON: Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis ("GAO-20-254").

[189] GAO-20-254.

[190] GAO-20-254 Recommendation Status, https://www.gao.gov/products/gao-20-254#summary_recommend.

Thus, EPA's unexplained deviation from the SC-GHG development approach laid out in E.O. 13990 not only upends the process to which API and other have devoted time and resources, it undermines the federal government's longstanding objective of making RIAs more consistent across agencies and detracts from what the GAO and this Administration identified as necessary to improve the SC-GHG estimation process consistent with the National Academies' recommendations.

3. Failure to Respond to Comments

As a further consequence of the Agency's decision to unilaterally develop its own SC-GHG estimates, EPA's SC-GHG Report does not appear to be based on any meaningful consideration of the many significant and detailed comments submitted to the IWG, including most recently, the many comments in response to the 2021 Interim TSD. Based on the Biden Administration's representation that the IWG alone would develop the SC-GHG estimates that would be used by the many agencies of the federal government, "[t]he Office of Management and Budget (OMB), on behalf of the cochairs of the Interagency Working Group on the Social Cost of Greenhouse Gases, including the Council of Economic Advisors (CEA) and the Office of Science and Technology Policy (OSTP)," requested "public comment on the interim TSD as well as on how best to incorporate the latest peer-reviewed science and economics literature in order to develop an updated set of SC–GHG estimates."[191]

Notwithstanding that the IWG purported to solicit public comments "in order to facilitate early and robust interaction with the public on this key aspect of this Administration's climate policy,"[192] neither the IWG nor EPA, which is a key member of the IWG, ever responded to or meaningfully considered the public comments submitted by API and many others in 2021. This does not represent a valid and transparent effort to engage the public and solicit feedback to improve agency decision-making.

"For an agency's decisionmaking to be rational, it must respond to significant points raised during the public comment period."[193] EPA is not relieved of this obligation simply because the comments were solicited by OMB on behalf of the IWG. As a key member of the IWG, EPA "reviewed the comments submitted to the IWG,"[194] and therefore had an obligation to "engage the arguments raised before it."[195]

The issues on which the IWG solicited comment, including advances in science and economics, approaches for implementing the National Academies' recommendations, approaches for intergenerational equity, and the use of discount rates,[196] are directly relevant to the EPA's SC-GHG Report. So too are the significant comments and data submitted by API and others in response to the IWG's solicitation.

In particular, API submitted detailed and constructive questions and comments on issues regarding the selection of discount rates, the ability to reasonably forecast impacts on expansive time horizons, and the importance of providing domestic SC-GHG values alongside global values. The IWG never responded to these comments and questions, and given the existence of these same concerns in EPA's SC-GHG Report, EPA plainly ignored API's comments as well.

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[191] 87 Fed. Reg. 24,669 (May 7, 2021).
[192] 87 Fed. Reg. at 24,670.
[193] *Allied Local & Reg'l Mfrs. Caucus v. EPA,* 215 F.3d 61, 68 (D.C. Cir. 2000).
[194] SC-GHG Report at 8.
[195] *Del. Dep't of Nat. Res. & Envtl. Control v. EPA*, 785 F.3d 1, 11 (D.C. Cir. 2015); *see Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 214 (D.C. Cir. 2013).
[196] 87 Fed. Reg. at 24,670.

It is not enough for EPA to suggest that it "has reviewed the comments submitted to the IWG in developing [the SC-GHG Report]."[197] EPA must respond in a reasoned manner to the comments received, [] explain how the agency resolved any significant problems raised by the comments, and [] show how that resolution led the agency to [its conclusion]."[198] "Consideration of comments as a matter of grace is not enough.' It must be made with a mind open to persuasion."[199]

It is also insufficient that EPA is now accepting comment on the SC-GHG Report. To begin, EPA's acceptance of comments on entirely new SC-GHG estimates in a wholly distinct SC-GHG Report in no way mitigates the absence of any record that EPA meaningfully engaged with or responded to any of the comments already submitted to the IWG.

Further, while it remains unclear what the SC-GHG Report is or how EPA intends to use it, nowhere does EPA represent that the report is in draft form or that the Agency will revise the SC-GHG Report based on comments and data received. On the contrary, EPA states that the "report presents new estimates of the SC-GHG" that EPA may rely upon "while [the IWG] process continues."[200] Therefore, if EPA intends to use and rely on the values in the SC-GHG Report as they are currently estimated, the Agency's solicitation of comments at this point does not truly "allow for public participation and an open exchange of ideas."[201] Nor is such an approach consistent with the National Academies' recommendation that draft revisions to the SC-GHG methods and estimates should be subject to public notice and comment, allowing input and review from a broader set of stakeholders, the scientific community, and the public.[202]

4. EPA has not Provided Interested Parties the Time or Information Necessary to Solicit Detailed and Constructive Feedback

In order for its public comment process to be reasonable and therefore lawful, EPA must provide commenters access to the data, studies, and other records on which the Agency relied as well as reasonably adequate time to review the data and draft comments analyzing EPA's conclusions and findings based on those records. EPA's present solicitation of comments on the SC-GHG Report does not satisfy either of these requirements.

The U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") makes clear that when an agency relies on data that is critical to its decision-making process, that data must be disclosed in order to provide the public an opportunity to meaningfully comment on the agency's rulemaking rationale.[203] Indeed, the D.C. Circuit has consistently maintained that "[i]n order to allow for useful criticism it is especially important for the agency to identify and make available *technical studies and data* that it has employed in reaching the decisions to propose particular rules."[204]

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[197] SC-GHG Report at 8.

[198] *Indep. U.S. Tanker Owners Comm v. Lewis*, 690 F.2d 908, 919 (D.C. Cir. 1982).

[199] *Advocates for Hwy & Auto Safety v. Fed. Hwy. Admin*., 28 F.3d 1288, 1292 (D.C. Cir. 1994) (citing *McLouth Steel Products Corp. v. Thomas*, 838 F2d 1317, 1323 (D.C. Cir. 1988)).

[200] SC-GHG Report at 84.

[201] E.O. 13563 at Sec. 1(a).

[202] National Academies of Sciences, Engineering, and Medicine 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*: Washington, DC: The National Academies Press ("NASEM 2017") at Pages 58-60.

[203] *See, e.g., Conn. Light & Power Co. v. Nuclear Regulatory Comm'n,* 673 F.2d 525, 530 (D.C. Cir. 1982); *Chamber of Commerce v. SEC,* 443 F.3d 890, 899 (D.C. Cir. 2006); *Am. Radio Relay League, Inc. v. FCC,* 524 F.3d 227, 236-37 (D.C. Cir. 2008).

[204] *Conn. Light & Power Co.,* 673 F.2d at 530 (emphasis added); *See also Am. Radio Relay League, Inc.,* 524 F.3d at 237 ("It would appear to be a fairly obvious proposition that studies upon which an agency relies in promulgating a rule must be made available during the rulemaking in order to afford interested persons meaningful notice and an opportunity for comment.").

Moreover, because of the "complex scientific issues involved in EPA rulemaking" Congress established more rigorous requirements under the CAA for making information available for public scrutiny.[205] Hence, the CAA mandates that "[a]ll data, information, and documents . . . on which the proposed rule relies *shall* be included in the docket on the date of publication of the proposed rule."[206] This critical requirement is particularly relevant here because EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, which is a rulemaking pursuant to the CAA.[207]

Therefore, if "documents of central importance upon which EPA intended to rely had been entered in the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."[208] "The Congressional drafters, after all, intended to provide 'thorough and careful procedural safeguards . . . [to] insure an effective opportunity for public participation in the rulemaking process.'"[209]

Notwithstanding this requirement, EPA's docket omits several studies, records, and other materials that appear fundamental to the Agency's development of the SC-GHG Report. For instance, EPA claims to have based several aspects of the SC-GHG Report on "the public comments received on individual EPA proposed rulemakings and the IWG's February 2021 TSD,"[210] but only identifies two supportive comments of the 88 total comments submitted on the 2021 TSD.[211] EPA did not identify or provide any comments "it received on individual EPA proposed rulemakings." Therefore, the Agency's administrative record for the SC-GHG Report is either insufficiently comprehensive or EPA impermissibly "rel[ied] on some comments while ignoring comments advocating a different position."[212]

Similarly, the SC-GHG Report relies extensively on SC-GHG estimation and modeling approach developed by RFF,[213] but while EPA's administrative record includes the RFF paper itself, it does not include all the data and studies that RFF utilized in developing those projections and estimates that EPA incorporated into its SC-GHG Report. For instance, RFF augments their economic forecast and generates their emissions forecast based on expert opinion,[214][215] but EPA's administrative record does not appear to contain any details or documentation regarding the expert elicitation and forecasting that was a key part of RFF's modeling effort. Given the critical importance of these forecasts in modelling the SC-GHG and EPA's implicit adoption of the forecasts in the SC-GHG Report, EPA should provide the public with details regarding how and why these experts were selected. For example, EPA should submit for public comment in the docket for the Proposed NSPS Revisions RFF's documentation, which details RFF's survey methodologies, partial selection methodology, and results. EPA should also extend the time period for submission of public comments on EPA's SC-GHG Report. Additionally, EPA should foster transparency by clarifying how RFF selected their experts from RFF's nominee pool.

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[205] *E.g., Small Ref. Lead Phase-Down Task Force v. EPA,* 705 F. 2d 506, 518 (D.C. Cir. 1983).

[206] CAA § 307(d)(3) (emphasis added); *see Kennecott Corp. v. EPA,* 684 F. 2d 1007, 1018 (CAA § 307(d)(3) requires EPA to place in the docket "the factual data on which the proposed regulations are based").

[207] 87 Fed. Reg. at 74,713.

[208] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (D.C. Cir.1981); *See also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C.Cir. 1982) (EPA improperly placed economic forecast data in the record only one week before issuing its final regulations).

[209] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (citing H.R.Rep.No.95-294, 95th Cong., 1st Sess. 188 at 319 (1977)).

[210] SC-GHG Report at 26, 37, 53, and 8.

[211] SC-GHG Report at 14 (FN26), and 15 (FN37).

[212] *National Women's Law Center v. Office of Management and Budget*, 358 F. Supp. 3d 66, 91 (D.D.C. 2019).

[213] Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. Brookings Papers on Economic Activity. Fall 2021, pp.223-305.

[214] Rennert et al.'s economic growth survey included the following participants: Daron Acemoglu, Erik Brynjolfsson, Jean Chateau, Melissa Dell, Robert Gordon, Mun Ho, Chad Jones, Pietro Peretto, Lant Pritchett, and Dominique van der Mensbrugghe.

[215] Rennert et al.'s future emissions survey included the following participants: Sally Benson, Geoff Blanford, Leon Clarke, Elmar Kriegler, Jennifer Faye Morris, Sergey Paltsev, Keywan Riahi, Susan Tierney, and Detlef van Vuuren.

More fundamentally, as discussed in Section III.a.1, EPA's administrative record does not even sufficiently apprise the public as to why EPA developed the SC-GHG Report or how the Agency intends to use it. However, even if EPA had timely provided all of the documents of central importance upon which it relied in drafting the SC-GHG Report, the public comment period EPA provided remains woefully insufficient. The SC-GHG Report provides a completely new set of SC-GHG estimates that were generated through a substantially revised modular approach using entirely different methodologies, models, studies, data, and analytical framing decisions than have been used by the IWG. And while EPA has not populated the administrative record with the full universe of the centrally important records on which it relied, there are hundreds of sources cited in the SC-GHG Report and the RFF Study that provided significant portions of the analysis used in the SC-GHG Report. As evidenced by the five years it took RFF to develop its SC-GHG estimates[216] and the fact that the IWG is more than a year overdue in developing the final SC-GHG estimates required by E.O. 13990, reviewing SC-GHG estimates and their underlying methodologies and data is incredibly labor-intensive and time-consuming.

As such, EPA's decision to provide the public only 69 days to review, develop, and submit comments on the SC-GHG Report is plainly unreasonable – particularly so, given that the comment period coincided with the holiday season. EPA's comment deadline for the SC-GHG Report is also unreasonable because it is the same comment period through which EPA is soliciting comments on the Proposed NSPS Revisions. The proposed revisions are complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under the CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, the current comment deadline is insufficient for even the Proposed NSPS Revisions alone.

In sum, EPA's current administrative record and comment deadline for the SC-GHG Report do not reasonably "allow for public participation and an open exchange of ideas."[217] API therefore respectfully requests that EPA supplement the administrative record with all of the centrally relevant information EPA utilized in developing the SC-GHG Report and provide a new and substantially longer comment period focused exclusively on the SC-GHG Report and the estimates contained therein.

b. <u>Technical Issues with EPA's Methodology and Presentation of the SC-GHG Estimates</u>

In addition to the procedural issues API described in the preceding subsection, our review of the SC-GHG Report raised several significant questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. It is critical the SC-GHG Report completely and transparently explain the precise bases for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Moreover, given the enormous and continually growing body of data and academic literature relevant to estimating the SC-GHG, the process by which EPA selects the data and literature on which it relies must be rigorous, objective, and transparent. Thus, when describing the evidentiary bases for its SC-GHG estimates, the SC-GHG Report should not only identify the studies on which the Agency relied, it must reasonably explain and describe why EPA declined to utilize other credible academic literature and data.

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[216] https://www.resources.org/archives/the-social-cost-of-carbon-reaching-a-new-estimate/?_gl=1*becwm3*_ga*OTczMDg2OTQzLjE2NzQ3NTAyOTI.*_ga_HNHQWYFDLZ*MTY3NDg0OTI4Ny4yLjEuMTY3NDg0OTMyMi4wLjAuMA.

[217] E.O. 13563 at Sec. 1(a).

The bullets below briefly describe a number of the questions and concerns that API and its members raised after reviewing the SC-GHG Report. Given the constrained timeframe for review and comment, these questions and concerns should by no means be considered exhaustive or complete. Rather, we urge EPA to view these questions and concerns as emblematic of API's broader concern with the manner in which the SC-GHG Report describes and supports EPA's model choices and SC-GHG estimation process.

- **Damage functions** – Two of the damage functions used in EPA's new SC-GHG model estimate damages at a subnational and/or sectoral level. However, there is no discussion about why EPA excluded other damage functions, particularly those produced by structural economy-wide models.[218] EPA should identify all the possible damage function approaches that could be incorporated and discuss the relative merits and shortcomings of each so stakeholders can understand EPA's rationale for their selected approach.

  Furthermore, given the relative importance of mortality-related impacts in the two sectoral damage functions, EPA should place more attention on how response functions could be adjusted for differences in age distributions across regions. Carleton *et al.* 2020 demonstrated that the temperature-mortality response function differs substantially by age, with a particularly strong relationship observed in the 65+ population. While age is included as a covariate in some of the studies included in Cromar *et al.* 2022, it is not uniformly considered across the literature assessed there. For example, the studies that do adjust for age do not present full mortality results by age. Cromar *et al.* did not consider heterogeneity by age group in their models estimating future mortality associated with temperature changes even though some of the individual studies included in Cromar *et al.* accounted for age. The ideal temperature-mortality model and subsequent monetization would account for age group heterogeneity at all stages of the analysis and calculations.

  Additionally, the temperature-mortality function for a given location and population will likely change through implementation of adaptation measures, a critical consideration in the SC-GHG estimation for mortality. However, adaptation is not consistently incorporated into these studies; and those studies that include adaptation vary in the way it is incorporated. In Carleton *et al.* 2020, administrative level 2 gross domestic product ("GDP") per capita and mean annual temperature for each location incorporates adaptation such that the location-specific exposure-response curve accounts for heterogeneity in adaptation response. Cromar *et al.* did not incorporate adaptation measures at a global or region-specific level, despite stating the importance of incorporating adaptation. As these measures will vary by many factors, including the regional climate and socioeconomic status, it is important that any future projections of the temperature-mortality function account for potential adaptation to temperature change, and the ideal study would account for adaptation at the local level.

- **Discount rate** – There are several choices regarding the discount rate that deserve more consideration and discussion. First, EPA should more fully justify its claim that long-term structural breaks in the interest rate imply lower interest rates in the future.[219] EPA should also explain how near-term interest rates from the last thirty years can fully inform the choice of an appropriate discount rate for the SC-GHG given the projection horizon of 300 years. Other work[220] has considered interest rates over long-time horizons and disputed the notion of structural breaks which calls into question some of EPA's discount rate assumptions. Furthermore, EPA should

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[218] Rose, S, D Diaz, T Carleton, L Drouet, C Guivarch, A Méjean, F Piontek, 2022. Estimating Global Economic Impacts from Climate Change. In Climate Change 2022: Climate Impacts, Adaptation, and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the IPCC, Chapter 16.

[219] *See* SC-GHG Report at 59.

[220] Rogoff et al. 2022. Long-Run Trends in Long-Maturity Real Rates 1311-2021. National Bureau of Economic Research.

explain their rationale for using a single discount rate for all regions, given that certain parameters used to estimate it, such as the economic growth rate, clearly vary across regions.

Second, since EPA estimates Ramsey parameters using assumptions about these near-term interest rates, EPA should consider whether the implied Ramsey parameters are reasonable and consistent with other available information. For example, the pure rate of time preference (ρ) that EPA estimates under the 2 percent near-term discount rate (0.2 percent) is significantly lower than those found in the Drupp *et al.*[221] survey cited in the SC-GHG Report.[222] Moreover, the value of ρ under the 1.5 percent near-term discount rate is near-zero, even though as EPA notes "it has been argued that very small values of ρ can lead to an unreasonable rate of optimal savings (Arrow et al. 1995), particularly with η around 1 (Dasgupta 2008, Weitzman 2007)."[223] Such results further call into question the choice of near-term discount rates and the reasons why parameters such as the Ramey parameters were forced to accommodate particular near-term discount rates, rather than the opposite.

Third, related to the calibration, EPA should state and explain how it calculates the near-term real growth rate of consumption per capita (g_t) as this is one of the few elements within the Ramsey discount rate that is observable in the market. To recover EPA's Ramsey parameters, a near-term consumption per capita growth rate of around 1.45 percent would seemingly be needed. Given that EPA appears to use the GDP per capita growth rate as a proxy for the consumption per capita growth rate, it is unclear why EPA derives its consumption per capita rate as the EPA notes "in the past decade average global per capita growth rates have been closer to 2%,"[224] and over the longer term global per capita growth rates have been higher. Once again, such results call into question why the growth rate was forced to accommodate other assumptions, rather than the opposite, given that the growth rate is the most observable of all the terms in the Ramsey equation.

Fourth, EPA should clarify how it estimates the near-term consumption growth rate "net of baseline climate change damages," and provide a practical example of how it calculated the consumption growth rate "net of baseline climate change damages" beyond what is offered in Appendix 3 of the SC-GHG Report. Moreover, EPA should discuss how climate damages affect the growth rate. If damages are assumed to impact investment (which would affect future economic output, and thus the growth rate), this seems to contradict EPA's assumption that damage functions are specified in consumption-equivalent units.[225]

Fifth, given the assumption of a constant savings rate, EPA should explain the basis for the specific savings rate and the methodology used. Similarly, EPA should discuss how the SC-GHG estimates would change if the savings rate varied at the national or regional given historical trends.

- **Geographic scope and reporting** – EPA lists several reasons for selecting a global SC-GHG—including the potential impacts on U.S. citizens living abroad, U.S. overseas military bases and investments, and regional destabilization caused by climate change. However, non-US impacts estimated by the damage functions used by EPA do not correspond to these impact categories. For example, total non-US mortality damages are not a reasonable estimate of the impacts on U.S. citizens living abroad. Therefore, EPA should consider and discuss reasonable alternatives for estimating potential impacts to U.S. interests that occur in other countries. In

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[221] Drupp *et al.* 2018. Discounting Disentangled. American Economic Journal: Economic Policy, 10 (4): 109-34.

[222] For the 1.5 percent consumption discount rate, EPA sets ρ to 0.01 percent and η to 1.02. For the 2 percent consumption discount rate, EPA sets ρ to 0.20 percent and η to 1.24. For the 2.5 percent consumption discount rate, EPA sets ρ to 0.46 percent and η to 1.42. Drupp *et al.*'s survey found that respondents' answers suggest a mean ρ value of 1.1 percent with a standard deviation of 1.47 and a median value of 0.5 percent.

[223] Drupp *et al.* 2018 at 61.

[224] SC-GHG Report at 22.

[225] *See* SC-GHG Report at 53.

addition, while EPA holds that not all spillover costs are properly attributed in regional breakdowns, as discussed further in Section III.c.1. below, the public would still benefit from SC-GHG estimates reported regionally, consistent with Circular A-4. EPA's SC-GHG Report also assumes that U.S. GHG mitigation activities, such as emissions pledges and the use of the global SC-GHG, engender international reciprocity. However, if EPA justifies the use of the global SC-GHG based on these factors, then the Agency should explain why its global emissions projection does not reflect globally coordinated action. Reasonable alternatives that maintain consistency between the geographic scope and the emissions trajectories should be considered and discussed.

- **Incorporation into regulatory cost-benefit analysis** – Given EPA's selection of a 1.5, a 2, and a 2.5 percent near-term discount rate, EPA's proposed SC-GHG discount rates no longer correspond to the typical regulatory consumption discount rate of 3 percent. Additionally, EPA's Ramsey discount rate approach further diverges from the constant discount rate approach used throughout federal cost-benefit analyses. Given that the announced revisions to Circular A-4[226] have not been finalized, API believes that it is inappropriate to incorporate EPA's new SC-GHG estimate in regulatory analysis until Circular A-4 is updated, as it is difficult to understand how EPA's SC-GHG approach for estimating climate benefits could be reasonably combined with other estimated benefits and cost streams discounted at different rates following standard A-4 guidance. For example, were EPA or another agency to use the EPA's SC-GHG estimates to present new benefit estimates in an RIA without updating the cost side of the ledger using the same near-term consumption discount rate used in the SC-GHG Report, the inconsistency between the discount rates used for benefits and costs would bias the cost-benefit analysis and undercut the rationality of the RIA's conclusions.

  EPA discusses the shadow price of capital, the preferred approach by Circular A-4, in Appendix 2 of the SC-GHG Report; however, EPA does not discuss whether or how the Agency plans to use this method in future cost-benefit analyses. To apply this method consistently, both benefits and costs must be adjusted in a similar manner. Whether this overall approach, or the revised discount rates themselves will improve cost-benefit analyses depends on whether and how Circular A-4 is updated to ensure consistency in how costs and benefits are estimated and compared. To avoid exacerbating inconsistencies, EPA should acknowledge this dependency and avoid using revised estimates until OMB guidance is updated, and all reviews are completed.

- **Underestimation of the SC-GHG** - EPA states that "The modeling implemented in this report reflects conservative methodological choices, and, given both these choices and the numerous categories of damages that are not currently quantified and other model limitations, the resulting SC-GHG estimates likely underestimate the marginal damages from GHG pollution."[227] This claim is repeated throughout EPA's SC-GHG Report. However, EPA should provide additional support for this assertion by listing and explaining the range of possible options and how the specific approach ultimately adopted by the Agency represents a conservative methodological choice. Repeating these assertions throughout the SC-GHG Report prior to completion of the IWG's peer review process may hamper objective analysis and may bias the IWG's review.

- **Market rates vs. purchase power parity** – EPA's SC-GHG Report states that "the shift to PPP-based projections in the RFF-SPs . . . represents another advancement in the science underlying the SC-GHG framework presented in this report."[228] However, Bressler and Heal (2022) contend that using "purchasing-power parity is incompatible with a pure Kaldor-Hicks approach."[229] Specifically, Bressler and Heal provide an example in which

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[226] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.

[227] SC-GHG Report at 2.

[228] SC-GHG Report 25.

[229] Bressler R., and Geffrey Heal. 2022. Valuing Excess Deaths Caused by Climate Change. National Bureau of Economic Research

a regulation would generate net costs when analyzed in PPP-adjusted dollars but would generate net benefits when analyzed using market exchange rates. EPA should therefore explain how using PPP-adjusted dollars is compatible with the federal government's overall approach to cost-benefit analysis.

c. The SC-GHG Report Should Fully and Explicitly Discuss the Limited Utility of the SC-GHG Estimates

EPA's SC-GHG Report avers that the SC-GHG estimates allow "analysts to incorporate the net social benefits of reducing emissions of greenhouse gases (GHG), or the net social costs of increasing such emissions, in benefit-cost analysis and, when appropriate, in decision-making and other contexts."[230] API agrees that from its earliest development by the IWG, the SC-GHG "was explicitly designed for agency use pursuant to E.O. 12866."[231] That is why the titles of each of the six TSDs the IWG published prior to the 2021 TSD disclaimed that they were "for Regulatory Impact Analysis under Executive Order 12866."[232]

While API agrees with the SC-GHG Report's statement that SC-GHG estimates are used in benefit-cost analysis, we believe EPA should clarify and describe the "decision-making and other contexts" the Agency believes may appropriately be based on SC-GHG estimates.[233] API agrees with the need to take action on climate change and we agree that agencies generally should weigh costs and benefits when considering such actions, but given the significant uncertainty and recognized malleability of SC-GHG estimates through modest changes to one or a few inputs, we cannot support expanded use of the Agency's or the IWG's SC-GHG estimates beyond their originally intended application in cost-benefit analysis. Indeed, in addition to, and in fact because of, the ease with which they can be "manipulated to reflect preferences, philosophies, assumptions, and so on,"[234] the SC-GHG estimates reflect such a broad range of uncertainty that in some contexts they may not effectively assist agencies' broad weighing of costs and benefits, as envisioned in E.O. 12866.

The SC-CH_4 values in EPA's SC-GHG Report and the IWG's 2021 TSD illustrate how agencies can struggle to use the estimates to determine whether a particular course of action will deliver more benefits than costs or *vice versa*. In the SC-GHG Report, the "nine separate distributions of estimates"[235] for avoided SC-CH_4 damages in 2030 range from \$1,100 per metric ton to \$3,700 per metric ton.[236] The 2021 TSD's estimates for avoided SC-CH_4 damages in 2030 range even more widely from \$940 per metric ton to \$5,200 per metric ton.[237] From a policy and regulatory perspective, the difference between \$940 and \$5,200 per metric ton or even \$1,100 and \$3,700 per metric ton is immense. A regulatory action that is imminently justifiable to mitigate damages estimated at the higher end of these ranges may be preposterous if proposed to avoid damages estimated at the lower end of these ranges.

"Such a wide range of . . . SC-CO_2 estimates is little more than a mathematical affirmation of the federal court's judgment that 'the value of carbon emissions reductions is certainly not zero.'"[238] "However, for the purpose the .

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[230] SC-GHG Report at 1.

[231] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[232] *See* 2010 TSD; May 2013 TSD; May 2013 TSD (revised); November 2013 TSD; August 2016a TSD (for CO_2); and August 2016b TSD (for Methane and Nitrous Oxide).

[233] API urged the IWG to provide the same clarification on multiple occasions.

[234] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 366.

[235] SC-GHG Report at 66.

[236] SC-GHG Report at 68.

[237] 2021 TSD at 5.

[238] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

. SC-CO_2 was developed— . . .RIAs[] for US federal regulations—such a wide range of SC-CO_2 is not necessarily a problem."[239]

The Electric Power Research Institute ("EPRI") examined 65 federal rules and 81 subrules between 2008 and 2016 that utilized the IWG's SC-CO_2 estimates in their regulatory analyses.[240] EPRI found that "the inclusion of benefits from policy-induced CO_2 emissions changes does not change the sign of net benefits. In other words, the net benefits are positive with and without consideration of CO_2 reduction benefits."[241]

Thus, while the broad range of uncertainty inherent in the IWG's SC-GHG estimates would appear to preclude their use in most cost-benefit analyses, in practice, the estimates have been used in analyses in which the difference between costs and benefits was larger than the SC-GHG estimates' range of uncertainty. This demonstrates that for those actions with non-climate benefits that are already estimated to exceed costs by a substantial margin, the IWG's SC-GHG estimates' range of uncertainty will not matter.

The extent of uncertainty and speculation that besets the SC-GHG estimates developed by the IWG and EPA alike precludes their reduction to a single value, be it a central value or otherwise. The IWG's SC-GHG estimates "were developed . . . with a methodology to fit the specific purpose of a benefits estimate to be added to a regulatory impact analysis . . ."[242] While EPA's SC-GHG Report adopts a modular approach in lieu of reliance on the IAMs used by the IWG, the reality of the SC-GHG estimation process is "that a high degree of uncertainty is baked in and cannot reasonably be estimated away."[243] At best, this enterprise is capable of producing "a very wide range of potential" SC-GHG estimates.[244]

> In aggregate, the SCC estimates developed by the interagency working group and others represent a strange marriage of conventional economic-financial logic, arbitrary economic-financial logic, massively expansive biophysical phenomena, preference, and uncertainty management utilized to create a digestible input – a dollar amount – for use in the dominant cost-benefit analysis . . . framework.[245]

Moreover, the subjective judgements that are necessary inputs into the SC-GHG estimation process make the product of those modeling exercises malleable. Indeed, SC-GHG estimates "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[246] Thus, "[f]or these assumptions, the tools of science, economics, or statistics are incapable of providing a 'best' or single value."[247]

> [P]roducing a wide range of SC-CO_2 estimates is simply the best we can do using this methodology, and it is the best we will ever be able to do. The . . . Central SC-CO_2 is not an optimal price of CO_2 emissions or a best estimate of the benefits of CO_2 reductions. It is a noncomprehensive estimate

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[239] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[240] Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.

[241] Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.

[242] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[243] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 364-5.

[244] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[245] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 348.

[246] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 369.

[247] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

> of the benefits of GHG reductions using one set of assumptions that is arguably defensible given the theoretical and methodological challenges associated with the approach.[248]

In addition to the methodological limitations precluding the use of the SC-GHG estimates in royalties, subsidies, fees, or applications that require a single value or narrow range of uncertainty, there are legal, statutory, and practical constraints on more expansive use of SC-GHG estimates as well. Indeed, courts have generally only upheld agencies' use of the SC-GHG estimates in the context of cost-benefit analyses.[249]

While some courts have held that agencies must estimate the costs of GHG emissions when assessing impacts of their proposed actions under the National Environmental Policy Act ("NEPA"), the agencies' impact assessments in those cases typically included cost-benefit analyses that are not required by NEPA.[250] In other words, because the agencies there estimated quantified benefits of certain actions, they also had to estimate quantified costs including of GHG emissions. In many other cases, courts have held that agencies have no obligation to use the SC-GHG estimates in analyzing impacts under NEPA.[251] Indeed, many of these courts took favorable views of agency determinations that SC-GHG estimates are ill-suited for NEPA analyses based on uncertainty ranges or otherwise.[252] Courts have generally taken a similar view to the Federal Energy Regulatory Commission's ("FERC's") prior position that the SC-GHG estimates' broad variability range makes them unsuited for public interest determinations[253] under the Natural Gas Act.[254] And in the context of collecting royalties and other financial obligations related to the leasing, production, and sale of minerals from federal and Indian lands, the federal government is affirmatively prohIbited from considering the SC-GHG estimates.[255]

Indeed, regardless of whether the Administration continues to rely on the IWG's estimates or those newly proffered by EPA in the SC-GHG Report, the SC-GHG estimates' broad range of variability and uncertainty render them inappropriate for use in any project-level or site-specific application. In addition, while analyses at these scales might be capable of monetizing some impacts (such as projected climate impacts), partial monetization is not advisable for several reasons. First, it could be interpreted as emphasizing or de-emphasizing the monetized impact, even though there is no basis on which to conclude that a monetized impact is more or less significant than a non-monetized impact. Second, monetized benefits and costs are only meaningful when they are compared to one another in aggregate.

These considerations illustrate the material distinction between formalized cost-benefit analysis in the regulatory context and other types of analysis. Whereas monetization is essential for regulatory analyses, it is potentially misleading outside this application for reasons discussed above. Notably, this material distinction is also embodied

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[248] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[249] Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 416.

[250] *High Country Conservation Advocates v. U.S. Forest Serv.*, 52 F. Supp. 3d 1174,1181, 1184 (D. Colo. 2014); *See also Mont. Envtl. Info. Ctr. v. U.S. Office of Surface Mining*, 274 F. Supp. 3d 1074, 1096-98 (D. Mont. 2017); *See also Citizens for a Healthy Community v. BLM*, 377 F.Supp. 3d 1223 (D. Col. 2019); *Contrast with WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41; *See also* Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 415.

[251] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020); *See also Citizens for a Healthy Cmty v. U.S. Bureau of Land Mgmt.*, 377 F. Supp. 3d 1223, 1239-40 (D. Colo. 2019); *See also WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 76 (D.D.C. 2019); *See also Wilderness Workshop v. U.S. Bureau of Land Mgmt.*, 342 F. Supp. 3d 1145, 1159 (D. Colo. 2018); *High Country Conservation Advocates v. Forest Service*, 333 F. Supp. 3d 1107 (D. Colo. 2018); *See also W. Org. of Res. Councils v. U.S. Bureau of Mgmt*., No. CV 16-21-GFBMM, 2018 WL 1475470, at *13 (D. Mont. Mar. 26, 2018).

[252] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020).

[253] *See* Natural Gas Act,15 U.S.C. § 717f(a), (c) (2012).

[254] *See, EarthReports, Inc. v. Fed. Energy Reg. Comm'n*, 828 F.3d 949,. 953-54 (D.C. Cir. 2016); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 867 F.3d 1357, 1375 (D.C. Cir. 2017) (remanding to FERC for a discussion of whether it still holds the *EarthReports* position); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 672 Fed. Ap 'x 38 (D.C. Cir. 2016).

[255] *See Wyoming v. Jewell*, No. 2:16-CV-0285-SWS (Oct. 10, 2020); *See also* 86 Fed. Reg. 31,196, 31,206 (June 11, 2021).

in E.O. 12866, which distinguishes between "regulatory actions" and "significant regulatory actions" based in part of the projected scale of impact. [256] For each "significant" proposed action, the issuing agency is required to provide a cost-benefit analysis. Thus, existing regulatory guidance essentially equates significance with the need for cost-benefit analysis, which in turn, implies full monetization of costs and benefits. While (as discussed above), there are inherent limits to the usefulness of SC-GHG estimates in rulemaking, consideration of SC-GHG values is sensible in situations where all costs and benefits are monetized. Consideration of the SC-GHG estimates is not appropriate in instances where only a subset of impacts can be monetized; accordingly, restricting its use to significant regulatory actions ensures consistency with this principle.

d. **The SC-GHG Report Needlessly Limits the Utility of EPA's SC-GHG Estimates by Failing to Present Domestic SC-GHG Estimates Alongside Global Estimates**

In order to conduct a valid and legally-defensible cost-benefit analysis, agencies must ensure that they weigh costs and benefits of the same scale and of the same type. Therefore, consistent with API's repeated requests to the IWG, API recommends that EPA's SC-GHG Report present domestic SC-GHG estimates alongside global estimates. Indeed, we believe that, absent a clear congressional directive otherwise, agency cost-benefit analyses should be constructed to weigh domestic costs against domestic benefits. By doing so, agencies can better ensure that projected domestic impacts alone justify the costs to be imposed on domestic industries. When agencies have failed to do so and weighed domestic costs against global benefits, they have effectively put their thumb on the scale in favor of regulatory action. Such an analysis is not only inconsistent with basic economic principles it overlooks "the more prosaic commonsense notion that Congress generally legislates with domestic concerns in mind."[257]

Given that EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, the CAA provides a particularly relevant example of why the geographic scope of agencies' regulatory analyses should reflect the intended scope under which the regulation is proposed or promulgated.[258] In CAA Section 101(b)(1), Congress expressly stated that the statute's purpose is to "protect and enhance the quality of the *Nation's* air resources so as to promote the public health and welfare and the productive capacity of *its population*."[259] By focusing on "the Nation" and "its population," Congress clearly demonstrated that it enacted the CAA to affect domestic air quality.

This interpretation of the CAA is not new, nor does it fail to reflect the global nature of climate change. Indeed, EPA relied on this interpretation when it issued the highly important Endangerment Finding on which multiple federal climate change regulatory actions have been based.[260]

In addition to the clear inferences that can be drawn from Congress' statements of statutory intent, the text of specific provisions of the statute confirms that Congress intended to limit the reach of the Act to domestic effects, unless it expressly provided otherwise. In only two discrete instances, Congress explicitly addressed the foreign effects of domestic air emissions in the CAA.

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[256] *See* E.O. 12866 at Sec. 3.

[257] *RJR Nabisco, Inc. v. Eur. Cmty.*, 136 S. Ct. 2090, 2100 (2016).

[258] 87 Fed. Reg. at 74,713.

[259] CAA § 101(b)(1) (emphasis added).

[260] *See* Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the CAA, 74 Fed. Reg. 66496, 66514 (Dec. 15, 2009) ("[T]he primary focus of the vulnerability, risk, and impact assessment is the United States").

First, in Title I of the Act, Congress authorized EPA to consider the foreign effects of domestic air emissions within the delineated framework of Section 115. There, Congress defined the process for EPA to evaluate and address reports of domestic air pollution possibly affecting public health or welfare in a foreign country.[261] Critically, this only applies when the Administrator finds there is "reciprocity" such that "the United States essentially [has] the same rights with respect to the prevention or control of air pollution occurring in that country as" Section 115 gives to the foreign country.[262]

Second, in Title VI of the CAA, Congress addressed the global impacts of domestic stratospheric ozone emissions by, among other actions, listing ozone-depleting chemicals of concern, establishing reporting requirements for manufacturers and other entities, and phasing out the production of certain chemicals.[263] Congress expressly enacted Title VI in 1990 in order to implement the Montreal Protocol on Substances that Deplete the Ozone Layer, an international treaty signed by the United States, which addresses stratospheric ozone.[264]

These two discrete provisions (Section 115 and Title VI) represent the full extent of EPA's authority to consider the international benefits of domestic regulation. Critically, these provisions demonstrate that, when Congress chose to allow the Agency to consider foreign impacts of domestic regulation, it said so expressly. These two provisions also reflect the very narrow purpose for which Congress allowed EPA to consider foreign impacts of domestic regulation. Both provisions deal with international agreements under which the United States and one or more foreign nations make reciprocal commitments to impose regulations within their borders that confer benefits outside their borders and/or to the other party.

In these two narrow circumstances, the United States is the beneficiary of EPA's action and also the foreign nation's reciprocal regulatory action. As such, while foreign impacts are considered, their consideration is solely intended to inform regulatory decisions seeking to maximize domestic benefits of reciprocal regulatory actions. The executive branch has ample authority to act for the benefit of foreign nations, but the CAA is generally not one of the statutes that confers that authority. With the exception of these two discrete provisions, the CAA arguably precludes EPA from weighing international benefits against domestic costs.[265]

In addition to the limitations that the CAA places on EPA specifically, OMB guidance applies these same principles government-wide. In support of limiting the use of international benefits for justifying regulation, OMB directs agencies developing regulatory analyses to focus on the "benefits and costs that accrue to citizens and residents of

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[261] CAA § 115(a)-(b).

[262] CAA § 115(c).

[263] EPA, 1990 CAA Amendment Summary: Title VI (Jan. 4, 2017), https://www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary-title-vi.

[264] 42 U.S.C. § 7671m(b) ("This subchapter as added by the CAA Amendments of 1990 shall be construed, interpreted, and applied as a supplement to the terms and conditions of the Montreal Protocol.").

[265] Settled principles of statutory interpretation further confirm that Congress did not intend to authorize EPA to rely on the foreign effects of U.S. emissions in promulgating regulations under the CAA. For one, statutes are construed to give effect to all provisions. *See, e.g., Hibbs v. Winn*, 542 U.S. 88, 101 (2004) ("A statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or superfluous, void or insignificant….") (citations omitted). Section 115 would effectively be a nullity if EPA read the Act to provide the Agency with the authority to consider effects of domestic emissions on foreign countries without following the Section 115 process. Moreover, it is also a well-settled canon that if Congress addressed an issue in one provision, its failure to address that same issue elsewhere confirms its limited intent. *See, e.g., Russello v. United States*, 464 U.S. 16, 23 (1983) ("[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (citations omitted).

the United States"[266] and directs agencies which "choose to evaluate a regulation that is likely to have effects beyond the borders of the United States" to report those impacts "separately."[267] OMB's guidance further states that an agency's cost-benefit analysis "should focus on benefits and costs that accrue to *citizens and residents of the United States*."[268]

Notwithstanding that OMB Circular A-4 mandates agency consideration of domestic costs and benefits while simply allowing for optional consideration of non-U.S. benefits, EPA's SC-GHG Report omits any calculation of domestic benefits. In lieu of this important, and arguably mandatory presentation of domestic benefits, the SC-GHG Report merely offers the EPA's justification for its absence.[269] While these justifications are perhaps sufficient to support the EPA's decision to present global benefits in the SC-GHG Report, none explain the Agency's refusal to also present an estimate of domestic benefits alongside the global value.

For instance, the IWG argues that analyzing the global benefits of U.S. regulatory actions can help generate reciprocal actions from other countries and "allows the U.S. to continue to actively encourage other nations . . . to take significant steps to reduce emissions."[270] Even assuming such effect occurs, the goal of the SC-GHG estimation process should not be the development of tools to aid in international negotiations or which help the U.S. "actively encourage" reciprocal actions on climate change; President Biden required use of the "best available economics and science"[271] to estimate as accurately as possible the societal costs of adding a small increment of GHG into the atmosphere in a given year. To the extent EPA is attempting to assume the IWG's assigned role of developing SC-GHG estimates, the Agency must also assume the obligation to dispassionately and objectively estimate the SC-GHGs using "best available economics and science."[272] And that obligation cannot be construed to encompass an advocacy role. Even if it were reasonable for EPA's interest in advocating for intergovernmental cooperation to shape how it estimates the SC-GHG, the EPA's SC-GHG Report provides no explanation why that advocacy role would be undermined by the presentation of domestic benefits *alongside global benefits*.

EPA also offers that:

> The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to the U.S. population.[273]

Although the U.S. could be adversely impacted by potential climate change damages that could occur in other countries, it does not follow that the EPA must therefore include the potential *damages in those other countries* as part of the SC-GHG estimate. Rather, the Agency should include in the SC-GHG estimates the potential *domestic impact* of those reasonably projected extraterritorial climate damages. As explained by the NASEM:

> Correctly calculating the portion of the SC-CO_2 that directly affects the United States involves more than examining the direct impacts of climate that occur within the country's physical borders . . .

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[266] OMB, Circular A-4, at 15.
[267] OMB, Circular A-4, at 15.
[268] OMB, Circular A-4, at 15 (emphasis added).
[269] *See* SC-GHG Report at 10-15
[270] SC-GHG Report at 14.
[271] E.O. 13990 at Sec. 5(b)(ii)(D).
[272] E.O. 13990 at Sec. 5(b)(ii)(D). Notably, and as previously discussed, E.O. 13990 expressly assigned the SC-GHG estimation development process to the IWG and precluded agencies from developing and using their own values.
[273] SC-GHG Report at 11.

> Climate damages to the United States cannot be accurately characterized without accounting for consequences outside U.S. borders.[274]

In other words, regardless of whether climate change imposes costs on the U.S. directly or indirectly through potential damages in other countries, the costs EPA should be attempting to characterize are those anticipated to be borne by the U.S. and its citizens. Thus, the global nature of climate change is consistent with and supported by the presentation of domestic benefits in the SC-GHG estimates. And the global nature of this issue certainly does not explain why the domestic benefits should not at least be presented alongside projections of global benefits.

EPA's final rationale for declining to present domestic benefits alongside global values is that there are relatively few region- or country-specific SC-GHG estimates or models with sufficient resolution to estimate SC-GHG benefits on a country-specific basis.[275] At the same time, EPA has largely limited its own consideration of damage functions to those that can be specified at the national or sub-national level, suggesting that domestic impacts could be reasonably estimated in two of the three frameworks adopted.[276] Although we agree that there is a high level of uncertainty in the regional or country-specific SC-GHG estimates, we believe it is inconsistent for EPA to use this uncertainty to rationalize its decision to decline to provide any SC-GHG estimates other than global, particularly given EPA's decision to severely restrict consideration of damage functions to precisely those that provide such information. Uncertainty and speculation pervade every aspect of the SC-GHG estimates, and the Agency should explain why such uncertainty provides a valid basis to decline to render estimates in this instance, but presents no barrier in every other respect.

It is also increasingly inaccurate for EPA to cite the overall paucity of literature on regional and country-specific SC-GHG estimates. As noted by the NASEM in 2017:

> Estimation of the net damages per ton of CO_2 emissions to the United States alone, beyond the approximations done by the IWG, is feasible in principle; however, it is limited in practice by the existing SC-IAM methodologies . . .[277]

Indeed, EPA's SC-GHG Report identifies a number of new models and academic efforts that have enhanced our ability to model SC-GHG benefits with greater spatial resolution.[278] While these country-specific estimates remain highly uncertain and divergent, they all broadly agree that the SC-GHG in the U.S. is a small fraction of the SC-GHG Report's estimates of the global SC-GHG.

Although country-specific SC-GHG estimates remain quite imprecise, they are highly relevant because EPA and other agencies should not adopt rules which could impose massive costs on the U.S., but for which the claimed benefits primarily accrue overseas—certainly not without a clear and explicit directive from Congress. EPA's assertion that rule writers and policymakers use only the global SC-GHG estimates in cost-benefit analysis results in

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[274] NASEM 2017 at 52-53.

[275] SC-GHG Report at 77-80.

[276] SC-GHG Report at 39 ("Based on a review of available studies using these approaches, the SC-GHG estimates presented in this report rely on three damage functions. They are: 1. a subnational-scale, sectoral damage function estimation (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (CIL 2022, Carleton et al. 2022, Rode et al. 2021)), 2. a country-scale, sectoral damage function estimation (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert et al. 2022b)), and 3. a meta-analysis-based global damage function estimation (based on Howard and Sterner (2017)).").

[277] NASEM 2017 at 53.

[278] SC-GHG Report at 77-80.

a significant misalignment of costs and benefits, particularly for regulatory actions, like the Proposed NSPS Revisions, that are promulgated pursuant to the CAA.

As such, API's modest recommendation, which we have also previously voiced to the IWG, is not that the federal government abandon the global SC-GHG estimates, but that it simply present domestic SC-GHG estimates alongside global values. This approach would allow risk managers to more readily align the costs with the benefits. Consistent with OMB guidance, the costs of a rule for entities in the U.S. should be presented in comparison with the benefits occurring in the U.S.

IV. CONCLUSION

API appreciates the opportunity to provide these comments on EPA's SC-GHG Report. We hope this comment opportunity is the first step toward a more open and transparent process for developing SC-GHG estimates and the judgment and assumptions used to develop and portray those estimates.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, EPA's unilateral development of SC-GHG estimates raises a number of questions and concerns the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the IWG.

President Biden's issuance of E.O. 13990 on his first day in office reflects the importance of the SC-GHG estimates to our nation's climate policies and regulations. Given the importance of these estimates, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each module had been updated and the SC-GHG Report had been fully drafted. Moreover, given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is wholly insufficient for soliciting detailed feedback from informed stakeholders.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. In fact, EPA has not even clearly explained why it developed the SC-GHG Report or how it intends the SC-GHG Report's estimates to be used. Nonetheless, where possible, API has tried to provide EPA relevant analysis and constructive recommendations for improving the reliability and utility of the SC-GHG Report and the estimates therein. We did so, not only with the intent of improving the SC-GHG estimates and the process through which they are developed, but with the hope that by providing credible analysis and constructive feedback, EPA would more fully recognize the benefit of engaging stakeholders in a more open, data-driven, and collaborative process.

API recognizes the need to confront the challenges of climate change. However, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. Indeed, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.

Thank you again for your consideration of these comments. If you have any questions or would like to discuss these comments, please feel free to contact Andrew Baxter at (202) 268-2800 or baxtera@api.org.

Sincerely,

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Submitted via regulations.gov

January 31, 2022

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

ATTN: Docket ID EPA-HQ-OAR-2021-0317
Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" including Proposed 40 CFR 60, Appendix K

Dear Administrator Regan:

The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 FR 63110, November 15, 2021). This submittal includes comments on the associated proposed Appendix K to 40 CFR Part 60, "Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging".

API is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Reducing methane emissions is a priority for our industry and we are committed to advancing the development, testing, and utilization of new technologies and practices to better understand, detect, and further mitigate emissions. In recent years, energy producers have implemented leak detection and repair programs, phased out the use of high-bleed pneumatic controllers, and reduced emissions associated with flaring – voluntarily and under federal and state regulations. In addition, API supports industry-led initiatives, such as The Environmental Partnership, to build on the progress industry has made to reduce emissions and continuously improve environmental performance. Founded in 2017, The Partnership has grown to nearly 100 oil and natural gas companies committed to continuously improving their environmental performance by taking action, learning about best practices and technologies, and fostering collaboration. Collectively, the coalition represents over 70% of total U.S. onshore oil and natural gas production and the program is being implemented in 41 of 50 states. Each year, the participating companies report[1] their implementation of the program's six Environmental Performance Programs, including programs for leak detection and repair, gas-driven pneumatic controllers, liquids unloading, compressors, pipeline blowdowns and flare management.

API supports the cost-effective direct regulation of methane from new and existing sources across the supply chain, and directionally supports the EPA proposal to reduce VOC and methane emissions. We especially appreciate EPA's inclusion of an alternate fugitive emissions monitoring option that allows for use of advanced detection technologies. The ability to take advantage of new and emerging technologies allows for monitoring programs that can more effectively identify and address larger emission events. Our comments include suggestions to further enhance the alternate monitoring framework.

In our review of the proposal, API considered the effectiveness of emission reduction strategies, safety, feasibility, operability, and cost, and where appropriate, we have recommended alternative approaches. As no rule text has been provided in this initial proposal, our comments are based on our best understanding of the requirements as they have been described in the preamble. This assessment could be modified once the requirements are provided in EPA's supplemental proposal. We encourage EPA to provide adequate time for stakeholders to review and comment on the supplemental proposal that is accompanied by regulatory text.

As further outlined in our comments, we do not believe the proposal publication date can set the Subpart OOOOb new source applicability date because the proposal lacks proposed regulatory text. Without regulatory text, affected facilities cannot know with certainty what regulatory requirements EPA has proposed and are thus unable to reasonably plan to comply with the final rule. The new source applicability date should be set when proposed regulatory text is published in the Federal Register as part of EPA's supplemental proposal.

With respect to proposal requirements for new (NSPS OOOOb) and existing (EG OOOOc) sources, we generally support, with recommended changes to Appendix K and its application, the provisions for fugitive emissions monitoring at well sites, compressor stations, and gas processing plants. The proposed Appendix K Optical Gas Imaging (OGI) protocol is not appropriate for use in the production and transmission sectors, where OGI monitoring specifications should continue to be based on NSPS OOOOa requirements. With our recommended modifications to Appendix K, we support its application for gas processing plants, petroleum refineries, and similar facilities.

In addition to fugitive emissions monitoring requirements, we also generally support, with certain modifications, the proposal requirements for new and existing pneumatic pumps, storage vessels,

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[1] https://theenvironmentalpartnership.org/annual-reports/

reciprocating compressors, centrifugal compressors (other than existing centrifugal compressors located in Alaska), gas well liquids unloading, and oil well associated gas.

With respect to proposed requirements for pneumatic controllers, we generally support EPA's proposal for new and existing gas processing plants and for new well and compressor station surface sites, provided there is an option to route vented emissions to a control device. We provide recommended changes to the applicability of pneumatic controller requirements for existing well sites and compressor stations and to the definition of modification.

API's support of the EPA proposed requirements assumes that EPA provides adequate implementation schedules for certain types of modifications under OOOOb and for retrofitting existing sources under OOOOc.

API is committed to working with EPA and the Administration as it develops and finalizes regulations that are cost-effective, facilitate innovation and further the progress made in reducing emissions, to ensure that the oil and natural gas industry can continue to provide the world with the affordable, reliable energy it needs while reducing emissions and addressing the risks of climate change.

If you have any questions regarding the content of these comments, please contact Cathe Kalisz at kaliszc@api.org.

Sincerely,

Attachments

cc:
Joe Goffman - EPA
Tomas Carbonell - EPA
Peter Tsirigotis - EPA
David Cozzie - EPA
Steve Fruh - EPA
Karen Marsh - EPA
Amy Hambrick - EPA

API Comments on EPA’s “Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review”

(Proposed NSPS OOOOb, EG OOOOc and Proposed Appendix K)

Docket ID: EPA-HQ-OAR-2021-0317

January 31, 2022

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PROPOSED NSPS AND EMISSIONS GUIDELINES FOR THE OIL AND NATURAL GAS SECTOR (NSPS OOOOb AND EG OOOOc) INCLUDING PROPOSED APPENDIX K
DOCKET ID: EPA-HQ-OAR-2021-0317

1.0 INTRODUCTION

API supports the direct regulation of methane for new and existing oil and natural gas sources and remains committed to working with EPA and the Administration to identify cost-effective emission control opportunities. We support the goal of promoting environmental justice, and our members are committed to constructive interactions among industry, regulators, and surrounding communities that may be disproportionately impacted.

These comments provided herein focus on technical and feasibility challenges with certain provisions described by EPA for proposed NSPS OOOOb and EG OOOOc. Our members look forward to continued dialogue and engagement as EPA works towards the supplemental proposal.

The major concerns identified by our members during this initial comment period include the following:

- **EPA took a very rare step when it issued this preamble-only proposal. The absence of regulatory text underscores the need for EPA to reset the applicability date for the proposed rules.** The current proposal's NSPS OOOOb applicability date means the inventory of affected facilities is currently growing (particularly existing facilities that are modified) without known compliance obligations, as there is no formal regulatory text to follow. The new source applicability date should be set when proposed regulatory text is published in the Federal Register, and EPA must provide sufficient opportunities for public comment, including on elements of the currently available portion of the rule, when definitions, applicability, and other relevant details are available in regulatory text. Furthermore, given the lack of regulatory text and the short comment period timeframe, we have not had an opportunity to fully analyze the Regulatory Impact Analysis (RIA) and the overarching cost effectiveness of the proposed rule. We will continue to pursue and provide more detailed input when we see the regulatory text in the supplemental proposal.

- **OGI monitoring protocols for production facilities and compressor stations should be based on NSPS OOOOa requirements, not Appendix K.** While API supports the use of Optical Gas Imaging (OGI) technology, Appendix K as drafted is unnecessarily burdensome for utilization in upstream production facilities, gathering and boosting compressor stations, and transmission compressor stations. Comments offered below (refer to Comment 4.0) expand on our concerns and outline some of the initially identified feasibility challenges in greater detail. The requirements specified in NSPS OOOOa that are currently used by operators have consistently proven to be effective and are more appropriate for use in upstream applications. Accordingly, we recommend EPA revise its proposal to limit the applicability of Appendix K to refineries; gas plants; and, potentially, similar larger process operations in other industries.

- **Significant modifications to Appendix K are necessary for the protocol to be feasible for implementation at refineries and natural gas processing plants.** Included in Attachments A and B are comments and suggested edits to allow the Appendix K protocol to be effectively implemented for use at refineries and gas processing plants. API's recommended changes are intended to proactively address concerns that the proposed requirements will result in difficulty in finding and retaining adequate numbers of qualified senior OGI operators; that the monitoring, training, and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and that the ownership of various requirements, particularly the recordkeeping requirements, are unclear and unnecessarily burdensome. The recommended changes also aim to make the Appendix K requirements more straightforward and efficient.

- **While we support reducing emissions from pneumatic controllers, the proposed provisions for pneumatic controllers must be re-evaluated.** We support moving towards non-emitting controllers for completely new construction surface sites; however, EPA has made no provision for addressing modifications at existing locations. The technical feasibility and cost effectiveness for moving towards non-emitting controllers from gas driven controllers fundamentally changes how an operator would approach the control strategy and operation of assets. As such, we offer EPA our suggestions for addressing NSPS modifications and for the retrofit of existing facilities under Emission Guidelines (EG).

- **Advanced leak detection technologies should be specified as an alternative BSER in addition to use of OGI and Method 21 (M21).** Allowing new leak detection technologies increases flexibility in how operators identify leaks and other process upsets. Allowing alternate technologies to be considered BSER will facilitate continued innovation in methane detection technology capabilities.

- **Guidance issued to state programs along with the Emission Guidelines should allow a minimum 3-year implementation period.** Operators with thousands of oil and gas facilities will need adequate time to plan for retrofits and obtain control devices or other specialized equipment, all while dealing with potential supply shortages. Additionally, the precedent for recognizing and providing adequate phase-in is well established. For example, EPA existing source rules under NESHAP (Subparts HH and ZZZZ), which require replacement or retrofit of existing applicable sources in the oil and gas sector, provided a minimum 3-year phase-in to complete work and establish compliance. Some emissions sources like pneumatic controllers may require a longer implementation period (even longer than three years) depending on the finalized regulatory requirements. Lastly, the ongoing limitations of the global supply chain may likely hinder operators' ability to obtain control devices and specialized equipment like solar panels. API strongly encourages EPA to ensure the formal regulatory text creates a feasible and reasonable pathway for operators to comply.

- **EPA should streamline all recordkeeping and reporting.** Within this proposal, EPA is soliciting numerous comments regarding information on the number and types of records operators should maintain and report to EPA. EPA should continue to streamline both recordkeeping and reporting as it relates to these proposed requirements to include only the necessary information that will help assure compliance. Streamlining is especially critical for locations with existing sources as the cumulative impacts for tracking records are anticipated to be much larger than EPA estimates and will apply to hundreds of thousands of locations across the U.S. For some sources, EPA has described requiring records and potential reporting of information that does not link directly to emission controls or affected facilities, which API does not support. We acknowledge and appreciate EPA's streamlining of recordkeeping and reporting in the 2020 Technical Rule updates and support the inclusion of provisions such as these which maintain environmental control standards and assure compliance with less administrative burden.

- **EPA should grant equivalency for state programs across emission sources for NSPS OOOOb.** Given EPA has described many requirements that are consistent with those at the state level (e.g., CO, NM, and CA), EPA should allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb where it is appropriate to do so for LDAR and other emission control provisions.

As explained in Comment 11.1, when using the terms "proposal" or "standards" in these comments it does not constitute a "proposed rule" or "emission standard" for purposes of triggering applicability under CAA § 111(a)(2).

2.0 PNEUMATIC CONTROLLERS

Due to the critical nature of pneumatic controllers for safety and operation of oil and gas facilities, we offer the following comments for EPA's consideration in crafting requirements that provide adequate flexibility for solutions to reduce pneumatic controller emissions. Unfortunately, there is not a "one-size fits all" solution, and EPA should allow an array of options for reducing pneumatic controller emissions.

Some specific technical challenges with EPA's described proposal for use of "zero-emitting" controllers which must be addressed under both NSPS OOOOb and EG OOOOc include:

- issues with facilities securing adequate electric grid power (as described in Comment 2.5);
- potential creation of net emissions increases due to on-site natural gas or diesel fired generators (as described in Comment 2.6);
- reliability risks associated with unproven solar-power systems including battery storage (as described in Comment 2.7); and
- hiring or training of personnel with expertise in the installation, use, and maintenance of electronic controllers, which will likely need to be done by a licensed electrician.

2.1 EPA should re-evaluate the proposed standards for pneumatic controllers at both new and existing facilities.

We support the concept of moving towards non-emitting controllers for the collection of pneumatic devices located at completely new construction sites provided an array of control options are allowed (refer to Comment 2.2) and there is a sufficient phase-in period (refer to Comment 2.11). However, we are unable to assess the feasibility of proposed requirements for modified sites because EPA has not delineated how modification of controllers is determined given the new control strategy proposed under NSPS OOOOb. We offer our solution in Comment 2.4.

For existing pneumatic controllers, we believe it is most appropriate to focus on conversion to non-emitting controllers at facilities with the largest number of controllers and with readily accessible grid power. We do not believe EPA should require a complete phaseout of properly functioning low bleed and intermittent controllers at existing facilities, as discussed further in Comments 2.9 and 2.10.

2.2 EPA should allow for the use of “non-emitting” pneumatic controllers versus “zero-emitting” pneumatic controllers.

While the change in terminology may appear subtle, EPA should amend its proposal to allow the use of “non-emitting” instead of “zero-emitting” controllers and allow for various technologies to achieve “non-emitting” status including the option of routing certain controllers to an existing combustion device if it is technically feasible to do so.

Even with this additional flexibility to route controllers to a combustion device, operators will need to evaluate the design and functional needs of the equipment at each site and determine the most appropriate path forward for achieving the “non-emitting” threshold defined for controllers. In remote locations without access to grid power, operators may require an approach that includes multiple solutions to achieve a “non-emitting” standard.

EPA should acknowledge and allow a more flexible approach for reducing emissions from pneumatic controllers for new and modified locations than what has been initially described in the proposal. Multiple options to reduce emissions include the following:

- pneumatic controllers driven by compressed instrument air,
- electric controllers,
- mechanical controllers, and
- routing natural gas controllers to a process, sales line, or combustion device.

2.2.1 State precedents allow flexibility in control options.

Colorado allows all options mentioned above and describes them as “non-emitting” in 5 CCR Regulation 7, Part D, Section III.

> *III.B.10. (State Only) "**Non-emitting Controller**" means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.*
>
> *III.B.12. (State Only) "**Routed Pneumatic Controller**" means a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.*

The proposed New Mexico Oil and Gas Sector Ozone Precursor Pollutants Rule[1] (Proposed 20.2.20.7 January 20, 2022) also uses the term "non-emitting controllers" to describe all these options which API prefers to "zero-emitting".

> *"**Non-Emitting Controller**" means a device that monitors a process parameter such as liquid level, pressure, or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.*
>
> *"**Pneumatic controller**" means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) and sends a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.*
>
> *"**High-Bleed Pneumatic Controller**" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.*
>
> *"**Low-Bleed Pneumatic controller**" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.*
>
> *"**Intermittent pneumatic controller**" means a pneumatic controller that is not designed to have a continuous bleed rate but is designed to only release natural gas above de minimis amounts to the atmosphere as part of the actuation cycle.*

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[1] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

> *"**Routed Pneumatic Controller**" means a pneumatic controller of any type that releases natural gas to a process, sales line, or to a combustion device instead of directly to the atmosphere.*

2.3 Under NSPS OOOOb, EPA should consider amending the affected facility definition to be the collection of pneumatic controllers at a well site or compressor station.

In the 2012 and 2016 NSPS for the oil and gas sector, EPA defined the affected facility as a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh (also referred to as a high-bleed controller). Given the control option was to use a device of similar function with a lower bleed rate, a single controller being the affected source was a technically feasible approach to reduce emissions.

In this proposal, EPA is fundamentally changing the control strategy for pneumatic devices, such that the control option occurs for the collection of pneumatic controllers at a facility by requiring design of the pneumatic system to be non-emitting. Converting a single pneumatic controller to a non-emitting device typically requires that all controllers at the facility be converted to non-emitting devices. Even by EPA's own cost analysis, EPA assumed the control options would occur at the site level and would not occur for an individual controller. Therefore, API suggests that EPA re-evaluate the definition for natural gas driven pneumatic controller affected facility to be considered as a collective versus an individual controller under NSPS OOOOb.

API is supportive of the use of non-emitting controllers for newly constructed well sites, tank batteries, and compressor stations. We offer the suggested affected facility definition based on current NSPS OOOOa language as follows:

> *Each pneumatic controller affected facility ~~not located at a natural gas processing plant~~, which is the collection of natural gas driven pneumatic controllers that vent to the atmosphere located at a well site, centralized production facility, or compressor station.*

2.4 Under NSPS OOOOb, modification for the collection of natural gas driven pneumatic controllers should be defined similar to what EPA has defined for the collection of fugitive components at well sites and compressor stations.

As mentioned, the new proposed control standards under NSPS OOOOb are designed to occur at a site or system level and not by individual controller. Therefore, installing a single pneumatic controller at an existing surface site should not trigger the requirement for retrofitting all controllers to the non-emitting standard. Given the fundamental change in control strategy, EPA must re-evaluate the affected facility definition for controllers and what actions constitute a modification at the site level (and not controller level).

As with any equipment, pneumatic controllers break from time to time and must be replaced. To manage controller maintenance and more easily determine if a modification has occurred, API requests that a modification to a collection of natural gas driven pneumatic controllers be defined similar to how EPA has defined modification in 40 CFR 60.5365a(i) and (j) for well sites, tank batteries, and compressor stations which is summarized as follows:

Collection of natural gas driven pneumatic controllers located at	**Actions that Trigger Modification for Pneumatic Controllers to Non-emitting**
Well Site	▪ A new well is drilled at an existing well site; ▪ A well at an existing well site is hydraulically fractured; or ▪ A well at an existing well site is hydraulically refractured.
Centralized Production Facility	The above actions listed under well site occur at the tank battery or a well site that sends production to the tank battery.
Compressor Station	▪ An additional compressor is installed at a compressor station; or ▪ One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station.

Under the above outlined concept, when a modification occurs, the operator would be required to retrofit the collection of pneumatic controllers at the well site, tank battery, or compressor station to non-emitting controllers. As described earlier, a non-emitting controller could include a natural gas controller routed to a process, sales line, or combustion device. Sufficient time will be required to phase-in these retrofits after NSPS OOOOb is finalized.

2.5 Technical Challenges with Grid Power Requirements

2.5.1 Access to grid power must be limited to commercially available onsite connections with sufficient and reliable power.

EPA must clarify that "access to power" means that commercial line power is available onsite, sufficient to cover the power/capacity requirements of the non-emitting pneumatic controller design of the facility, and which provides reliable and consistent coverage. It is not always logistically feasible to electrify a location from the grid due to issues outside of an owner/operator's control. These challenges include right-of-way (ROW) issues for placement of power lines, a landowner's right to not install power lines on their property[2], and/or distance from an available power line that contains sufficient power and capacity to connect the facility. Therefore, EPA must be clear that running new commercial power lines to any site is not EPA's intent given the practical, technical, and cost challenges this would cause at large scale implementation across the country.

2.5.2 Sufficient Volume and Quality of Grid Power

Equipment power requirements at oil and gas facilities are quite varied, ranging from instrumentation at a single well pad needing approximately 35 watts to operate all the way up to approximately 2,000 kilowatts at larger sites running more equipment on electrical power. The power demand required to operate equipment determines if single phase power (household) is adequate or if three phase power (industrial) is necessary. Single phase low volume power may be accessible in certain areas, but three phase industrial wattage levels may not be available. Furthermore, even with accessibility, there may not be sufficient levels to run a given site or field. Due to the challenges around the development of adequate power supply to remote locations and the temporary nature of some areas of oilfield demand, many sites are supplied by onsite generation through produced natural gas as a motive source or natural gas generators.

2.5.3 Right-of-Way Issues

The largest challenge to oil and gas operations having grid power is obtaining ROW access for power lines. On private lands, landowners may choose to never allow ROW, particularly on large ranches. On federal lands, the current lead time for installation is typically between 6 months up to 2 years. It should be noted that the longest lead times have been experienced on federal lands controlled under the Bureau of Land Management (BLM). Additionally, as the Administration pursues updates to other regulatory requirements, such as environmental reviews as proposed by the Council on Environmental Quality in the Phase 1 NEPA revisions, these challenges may be exacerbated by expanding requirements and protracted timelines. A Memorandum of Understanding (MOU) may be needed between the EPA and BLM and state land offices to expedite approval of ROW for grid power.

2.5.4 Even if logistically possible, it is unlikely to be cost effective to access off-site grid power to convert a site to non-emitting controllers.

Even without the foregoing concerns, the cost and timing to obtain grid access can be prohibitive when it is not readily accessible onsite. Since EPA did not include nor consider costs for installing new power lines in its cost benefit analysis, it is assumed EPA did not intend to require operators to run new commercial power lines in order meet proposed control requirements for pneumatic controllers. We support EPA in this approach, as this would not be cost-effective and would cause other environmental

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[2] In some states, the utility provider can implement eminent domain, but production companies would not and do not have this authority. Other states, such as North Dakota, do not have eminent domain authority.

disbenefits (e.g., potential land disturbance) in pursuit of eliminating emissions from a small number of ancillary controllers.[3]

As a point of reference, experiences with API member companies suggest an average estimated cost of approximately $200,000 per mile for installing an electrical line to a facility where one does not already exist. When this additional cost is considered for 1 mile of new power line and all other EPA assumptions remain, retrofit of pneumatic controllers is not cost-effective for small and medium model plants.

2.6 Emission reductions may be offset where a diesel or natural gas generator would be necessary.

There are numerous situations where operators legally cannot obtain grid power, where solar may not be a feasible option, or where an operator may plan for connecting to grid power, but delays occur. In these situations, operators will utilize a non-emergency natural gas or diesel generator to power a compressor instrument air system as the only option to achieve a non-emitting standard. This scenario could be true at either new or existing locations. The tradeoff in this situation is between creation of criteria pollutants and CO_2 from generators when other power sources are not available versus venting of methane.

According to input from API members, a natural gas-fired generator of approximately 200-hp would be needed to support reliable operation of a large instrument air system without grid power. Emissions from a generator this size are estimated to be 1.94 tons per year (tpy) of NO_X, 3.88 tpy of CO, 1.36 tpy of VOC, 0.12 tpy of PM_{10}, 0.14 tpy CH4 and 730 tpy of CO_2[4]. The generator emissions will have environmental impacts and offset the VOC and methane emission reductions from use of non-emitting pneumatic controllers.

2.7 Solar Power Technology Challenges

2.7.1 The long-term reliability of solar-powered technologies is still being evaluated.

Non-natural gas-driven pneumatic controllers include solar powered electric controllers and solar powered instrument air applications. For remote sites without grid access, some operators are piloting solar arrays with battery storage to power an instrument air system for pneumatic controllers. We are unaware of any operators converting to solar powered electric controllers at this time. While the technology seems promising, many of these solar systems have not yet been proven reliable for all

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[3] On page 8-21 of EPA's Technical Support Document issued with this proposal, EPA states "Since this electrical supply is assumed to be on the site irrespective of the electronic controllers at the site, the costs of the power supply were not included in the analyses of emission reductions and costs for electronic controllers."

[4] Emissions were based on AP 42, Vol. I, 3:2, applicable NSPS JJJJ limits, and 40 CFR 98, Subpart C for a 201-bhp natural gas engine operating 8,760 hours per year. Methane estimated based on 40 CFR 98, Subpart C.

remote locations or facility designs and are not ready for deployment across the country at the large-scale EPA's proposed rules would require. In 2014, EPA stated "solar-powered controllers can replace continuous bleed controllers in certain applications but are not broadly applicable to all segments of the oil and natural gas industry."[5]

For many sites, a solar-powered pneumatic controller system presents significant design challenges to overcome, including, but not limited to, the following:

- Large-scale solar applications have not yet been tested in winter months when there is more cloud coverage, increased snow cover, and less sunlight in more northern locations (Colorado, North Dakota, Idaho, Wyoming, etc.). Evidence suggests that even during periods without direct radiation, substantive energy is supplied to solar panels through ground reflection and diffused radiation. However, without adequate field-testing, it is probable that supplemental power via natural gas or diesel -powered generators could be required during winter months and/or severe weather events. This is necessary to ensure a continuous power supply, and, thus, controlled operation. Interruptions within the control system pose safety risks to operators and can damage processing equipment, which could potentially lead to excess environmental emissions associated with equipment malfunctions.

- As discussed in Comment 2.7.3, at temperatures at or below -20°C (-4°F), solar battery capacity is decreased to 50%. This reduces the overall life of the solar battery, which impacts the overall reliability and lifespan of the system. Further, if low temperatures cause freezing, an interruption to power supply for the pneumatic controller system will occur.

- For many sites, the impact to photovoltaic performance based on the level of particulate accumulation on the solar panel(s) is not well documented. This is important for remote, unmanned sites as challenges associated with properly cleaning the panels are encountered. The decrease in energy loss due to particle accumulation greatly varies based on several factors including site location, surrounding soil type, dust characteristics, and other surrounding air pollution.[6] One study suggests that in the U.S. over a 3-month period, up to 4.7% solar capacity is lost due to particulate accumulation on solar panels.[7]

2.7.2 Many solar system packages in use do not feature turnkey solutions available for mass installation and implementation.

Technology provided by certain vendors was referenced in the Carbon Limits study published in 2016,[8] which EPA relied upon in its cost effectiveness analysis. Industry representatives reached out to at least

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[5] Oil and Natural Gas Sector Pneumatic Devices, Review Panel, USEPA, OAQPS, 2014: https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf.

[6] Renewable and Sustainable Energy Reviews, Volume 59, June 2016, Pages 1307-1316. Renewable Power loss due to soiling on solar panel: a review, Mohammad Reza Maghami.

[7] Hottel, H, and Woertz, B. Performance of flat-plate solar-heat collectors. United States.

[8] Carbon Limits. *Zero emission technologies for pneumatic controllers in the USA.* August 2016

one of the vendors within the last six months to find out how much deployment there has been of these solar systems and electric controllers. The vendor indicated that in the past 10 years, they have conducted 200 retrofits and 300 new installs. Currently, the vendor projects it can only service approximately 200 installs per year.[9] Additionally, operators are already experiencing 6 to 12-month lead times for solar packages. The proposed rules will only exacerbate demand, increase costs, and increase pressure on the supply chain.

2.7.3 Additional technical challenges experienced with battery storage and capabilities prohibit use in some facility locations.

Remote oil and gas site applications for solar installations typically require up to 1,600 watt, 24 VDC capacity with a common battery type being an 8G8D gel cell (number of batteries required per application can range from 2 to more than 10). The exact number of solar sets is greatly variable based on site-specific requirements.[10] When sizing the solar system, in addition to site-specific requirements, the temperature profile of the site also impacts the type, number, and capable performance of batteries for solar packages. For example, the Deka 8G8D battery has an operating temperature range from -30°C (-22°F) to 50°C (122°F); however, the optimal operating range is above 0°C (32°F) because cold temperatures increase the internal resistance of a battery, thereby reducing capacity. The standard capacity rating of this example battery is based on each cell having an electrolyte temperature of 20ºC (68ºF).[11] At temperatures below the nominal rate, the battery's effective capacity is reduced, and the time to restore the battery to full charge is increased exponentially with decrease in temperature. Figure 1 displays the relationship between battery capacity and temperature for a Deka 8G8D solar battery; at -20°C (-4°F), battery capacity is decreased to 50%. Table 1 shows six states with significant oil and gas operations where temperatures fall in the range for reduced solar battery capacity during winter. Further, it is noted that the recent unprecedented winter storm in Texas (February 2021) saw a low temperature of -27° (-16°F).[12] Unfortunately, during severe weather days including snowstorms, solar panels are often not receiving sunlight and battery power is being used. Sufficient battery power at a high charge is needed for at least 7-10 days without sun. If the decreased sunlight lasts for too many days, batteries can freeze. Solar batteries in the oil field often freeze and stop functioning, particularly in areas where temperatures can drop to -40ºC (-40ºF).

On the other hand, extreme heat can also negatively affect battery performance and reliability. Though temperatures above 25ºC (77ºF) will slightly increase capacity, the potential of self-discharge and reduced battery life is increased. Further, as temperatures rise, any cycle life loss due to operating at higher temperatures is not recoverable. During extreme heat events, such as those experienced in Texas

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[9] Joint Industry Work Group comments submitted to CDPHE https://drive.google.com/drive/folders/1yXOxLue7DqPFutsxbq6SeThCMhc5S7DU

[10] Example of solar installations at oil and gas sites: https://www.scadalink.com/products/remote-power/industrial-solar-panels/.

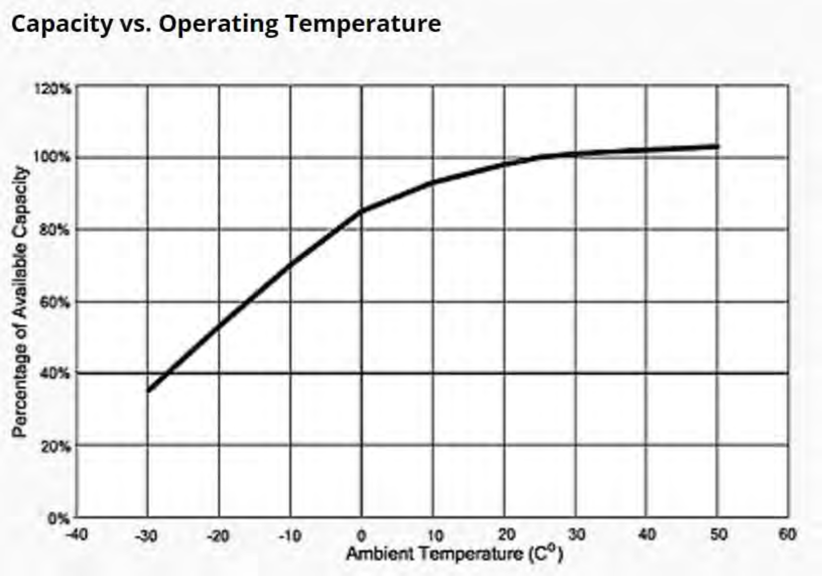
[11] Deka battery specifications: https://www.solarelectricsupply.com/solar-components/solar-batteries/gel-batteries/deka-8g8d-solar-batteries

[12] Feb. 2021 Texas Winter Storm Details: https://www.weather.gov/media/ewx/wxevents/ewx-20210218.pdf.

and Louisiana, overheating of the battery is possible. In this scenario, the battery lifespan can be shortened, or the battery can be completely damaged.

For nonessential equipment, losing power is not a concern. Pneumatic controllers are critical for safe operations. Due to the temperature profile of the key states in play, current solar battery performance may be too unstable for the operation of pneumatic controllers.

Figure 1. Capacity vs. Operating Temperature for Deka 8G8D Solar Battery



Source: https://www.solarelectricsupply.com/solar-components/solar-batteries/gel-batteries/deka-8g8d-solar-batteries

In addition to concerns related to temperature, the type and number of batteries required for remote industrial sites (e.g., gel lead acid batteries and absorbed glass mat (AGM) batteries) are on average higher in cost as compared to household solar panel systems.

Table 1. Winter Temperatures for some States with Oil and Gas Operations

State	Average Winter Temperature[13]		Record-Low Temperature[14]	
	°C	°F	°C	°F
North Dakota	-4	25	-51	-60
Texas	0	32	-30	-22
New Mexico	-16	3	-45	-49
Oklahoma	0	32	-35	-31
Colorado	-9	16	-52	-62
Alaska	-28	-18	-62	-80

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[13] Average temperatures based on 30-year records, for average of December – February: https://www.usclimatedata.com/climate/united-states/us

[14] Record-low temperatures: https://ggweather.com/climate/extremes_us.htm.

2.8 Review of EPA's Cost Benefit Analysis for Converting Pneumatic Controllers to Non-Emitting

2.8.1 EPA based their model plant analysis on incorrect assumptions.

Based on blinded data collected from API member companies by a third-party, EPA has underestimated the costs and overestimated the benefits for converting pneumatic controllers to non-emitting. A summary of EPA cost assumptions is provided in Table 2.

Table 2. Summary of EPA Estimated Capital Cost Assumptions for Pneumatic Controllers

EPA Model Plant Reference	EPA Estimated Capital Cost for Grid Power Electric Controllers[a]	EPA Estimated Capital for Solar Power Electric Controllers[b]	EPA Estimated Capital Cost for Grid Power Electric Instrument Air System
Small (4 controllers)	$25,494	$28,171	Not estimated
Medium (8 controllers)	$45,889	$51,242	Not estimated
Large (20 controllers)	Not estimated	Not estimated	New: $95,602 Existing: $127,469

a. EPA costs included the costs of controllers ($4,000 each) and a control panel for grid connection ($4,000). EPA also included installation and engineering estimates based on 20% of equipment costs, which equated to $4,420 for small model plants and $8,040 for medium. EPA did not include any annual operating or maintenance costs within their assumptions.

b. For solar electric controllers, EPA costs included cost of electric controllers ($4,000 each), a control panel ($4,000), 140 W solar panel ($500), and 100 Amh batteries ($400 each). EPA also included installation and engineering estimates based on 20% of equipment costs, which equated to $4,000 and $7,200 for the small and medium model plants, respectively. EPA did not include any annual operating or maintenance costs within their assumptions.

The variation in the costs estimated by EPA with API member costs is centered on incorrect assumptions by EPA that companies will use grid power or solar based systems to power electric controllers. API members have converted natural gas driven pneumatic controllers to compressed instrument air systems powered by the grid (when accessible) or natural gas generators and are only in the initial phases of testing the reliability of solar based instrument air systems.

Costs associated with a typical instrument air system include a regenerative dryer, inlet filter, tank to store compressed air, insulated enclosure for the compressor and dryer, junction box, controllers for the compressor system, and voltage boosters. Additional costs for solar based systems would include higher cost gel or AGM batteries, sufficient number of batteries, and higher numbers of solar panels required in areas of less sunlight such as for Wyoming and North Dakota. Additional costs associated with the use of natural gas or diesel generators to power instrument air systems might also include monthly rental fees. All instrument air systems typically require annual maintenance at a cost of between $2000 and $4000 per year. Installation of non-emitting controllers also requires shutting-in the well or facility, an additional cost which does not appear to be accounted for in EPA's cost analysis. Cost estimates based on our blinded member survey are provided in Table 3.

Table 3. Average API Member Feedback regarding Capital Cost for Non-Emitting Technologies: Instrument Air Systems

Estimated Capital Costs for Various Sized Instrument Air Systems	Grid Power Instrument Air System[a,b]	Solar Power Instrument Air System	Natural Gas Generator Instrument Air System
Small to Medium	$51,000	Not estimated	$60,000
Medium to Large	$80,000		$110,000
Multi-Well Site, Central Production Facility or Compressor Station (>100 controllers)	$143,333	$250,000[c]	$207,250

a. Assumes the facility has existing grid power including a step-down transformer already in place and converts to an electric power instrument air system.
b. If grid access is not available, average costs to run a new power line is an additional $200,000 per mile.
c. This includes the cost of the solar panels, batteries and conversion to electric controllers and based on existing facility design with actual production values and local meteorological conditions.

Additionally, member experience has indicated that EPA's distinction between the small and medium model plant is incorrect when it comes to cost variation since a site with either 4 or 8 controllers would be considered a relatively small facility with minimal equipment. Some multi-well sites, central production facilities and compressor stations may contain 100-200 controllers. These larger facilities are typically the types of facilities that operators have been successful in retrofitting pneumatic controllers to non-emitting in a cost-effective manner by placing the investment of retrofit on the facilities with the most controllers. It is not economic and sometimes not feasible to convert pneumatic controllers to instrument air, particularly at older facilities with less wells and lower production. Retrofitting becomes even more challenging and uneconomic in instances where the wellhead is not co-located with the facility, as each remote wellhead would need its own power generation.

Additionally, some members have found that certain pneumatic controllers can be routed to an existing combustion device for a nominal investment. Like pneumatic pumps, there are challenges with this approach as not all existing locations may have an existing combustion device and not all types of controllers at a facility can be routed to an existing combustion device.

2.8.2 Emission Factors Applied for Intermittent Controllers

API appreciates EPA utilizing emission factors from API's *Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas*.[15] However, we believe that the use of the average intermittent pneumatic device vent rate is incorrect in this application. In this same proposal EPA is proposing to include intermittent controllers within the monitoring framework by including them in the definition of fugitive component and considering their emissions in the determination of a site's potential methane emissions. Under this proposal, any intermittent device would be monitored routinely and repaired or replaced if malfunctioning, so the more appropriate emission factor that should be utilized is 0.28 scf whole gas/controller-hour and not the average emission factor of 9.2 scf whole gas/controller-hour as documented in API's 2021 GHG Compendium Table 6-15.[16] The average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or where the monitoring status is unknown. The normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program.

Emissions savings from this approach (i.e., the emission reduction benefit from fixing improperly functioning controllers) is currently already captured in EPA's cost-effective analysis for the proposed leak detection and repair (LDAR) requirements. This approach achieves nearly a similar level of emission reduction for much less investment by operators. This is especially true when converting a single existing high-bleed controller with a properly functioning intermittent controller that is part of a company's LDAR program. Furthermore, if an existing facility only contains properly functioning intermittent controllers confirmed through an LDAR program, then the cost effectiveness evaluation never becomes cost-effective for any amount of controllers even assuming EPA's own cost assumptions.

When we review EPA's cost effectiveness analysis, updating the intermittent controller emission rate to the properly functioning emission rate reduces the baseline emissions for each model plant significantly, which directly reduces the potential emission reductions. When coupled with the fact that EPA underrepresented the actual costs for conversion to non-emitting technologies, the cost-effectiveness for the proposal under NSPS OOOOb and EG OOOOc quickly becomes not cost-effective either for methane or VOC with or without savings.

In Attachment C, we evaluated the minimum number of controllers that would be cost effective to retrofit to an instrument air system powered by grid power or a natural gas generator, using the minimum costs listed in Table 3. The results indicate that for a facility containing low bleed controllers and properly functioning intermittent controllers, it would only be cost effective to retrofit if there were

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[15] API's Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas." Presented on November 7, 2019 in Pittsburg PA by Paul Tupper.

[16] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

at least 15 to 30 controllers, depending on the single/multi-pollutant, with or without savings approach, that EPA analyses.[17]

2.8.3 Retrofit of a single low bleed or intermittent controller is not cost-effective.

The cost effectiveness associated with converting a single low bleed or intermittent controller to a non-emitting controller using solar or electric power is summarized in Table 4. The results indicate it is not cost-effective to retrofit a single low bleed or intermittent controller. This analysis relied on controller system costs as provided in EPA's pneumatic controllers costs and emissions workbook for a small model plant. As we describe above, an API member survey suggests minimum costs are at least double the costs estimated by EPA for small model plants, which would best reflect the minimum costs associated with retrofitting a single controller. Based on this review, API suggests EPA exempt facilities from the non-emitting controller standard under NSPS OOOOb and EG OOOOc if there is only a single low bleed or intermittent controller present.

Table 4. Cost Effectiveness Estimates for Retrofitting a Single Low Bleed or Intermittent Controller

Retrofit Scenario as Outlined in EPA's Cost Effectiveness Analysis	Cost Effectiveness ($/ton) Without savings		Cost Effectiveness ($/ton) With Savings	
	VOC	Methane	VOC	Methane
Single low bleed to solar	$28,312	$7,870	$27,659	$7,689
Single low bleed to electric grid	$25,621	$7,122	$24,969	$6,941
Single properly functioning intermittent to solar[a]	$262,893	$73,078	$262,240	$72,896
Single properly functioning intermittent to grid[a]	$237,912	$66,134	$237,260	$65,952
Single unknown intermittent to solar	$8,001	$2,224	$7,349	$2,043
Single unknown intermittent grid	$7,241	$2,013	$6,588	$1,831

a. Emission factor for properly functioning pneumatic controller as referenced in Table 6-15 in the Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry.[18]

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[17] To estimate baseline emissions, we assumed a mix of controllers onsite of 30% low-bleed and 70% intermittent, which is consistent with the breakdown of controller types reported to EPA for the 2020 calendar year pursuant to 40 CFR Part 98, subpart W. EPA was incorrect to assume a high bleed pneumatic controller within their model plant analysis as the count of high bleed controllers is only 1% for the production segment and 3% for the gathering and boosting segment based on the 2020 Subpart W data (refer to Attachment A, Table C-1). We also applied the properly functioning emission factor from Table 6-15 of API's GHG Compendium based on the comments offered herein.

[18] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

2.9 EPA should not require a complete phaseout of properly functioning intermittent and low bleed natural gas driven pneumatic controllers at existing facilities.

Many existing well sites are low producing wells that could be close to end-of-life of their production cycle and may only contain a limited number of controllers. The complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production. Furthermore, existing well pads may have sizing constraints for the proper placement (due to safety and other permitting constraints) of control systems, compressors that must sit outside of classified areas, generators, or solar panels. For these reasons, the state regulations EPA cites in support of this proposal, including Colorado and the current proposed version of regulations pending in New Mexico[19], do not require all existing controllers to be retrofitted as EPA has proposed. Colorado's regulations, as well as the draft regulations pending in New Mexico, concluded this is unwarranted as controller retrofit is not cost-effective nor technically feasible for many facilities.

2.10 For EG OOOOc, retrofit to non-emitting controllers should be based on the availability of onsite grid power and a minimum number of gas-driven pneumatic controllers. Absent feasibility to retrofit, the use of continuous low bleed and intermittent natural gas controllers should be allowed and covered in an operator's existing LDAR monitoring program to monitor proper functioning.

For existing locations, API supports EPA's proposal to retrofit to non-emitting controllers, as we define in Comment 2.2, where the following criteria are met:

a) There are at least 15 controllers at the well site, central production facility, or compressor station; and
b) There is access to sufficient and reliable grid power onsite.

If the above criteria are not met, then any high-bleed natural gas driven controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company's LDAR monitoring program to monitor proper functioning. This approach is similar to and based on the rationale for EPA's proposed requirements for pneumatic controllers at sites in Alaska without grid access.

Refer to Comment 2.8 and Attachment C for API's determination of the minimum number of controllers required for retrofit to be cost effective.

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[19] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

2.11 Adequate implementation time must be provided for pneumatic controller requirements under both NSPS OOOOb and EG OOOOc.

For modified sites (as outlined in Comment 2.4) and existing source retrofits, operators will need sufficient time for identifying devices for replacement or retrofit, designing and engineering systems, planning, budgeting, purchasing equipment, contracting labor, scheduling the work required and prioritizing equipment for retrofit. To retrofit a facility with instrument air, an engineer first verifies that adequate power is available and then applies for necessary permits, which takes approximately 60 days to acquire (if approved). During construction, an instrument air header and compressor skid must be added to the facility. The air compressors must sit outside of classified areas and therefore, some older reclaimed facilities may not have space to add necessary equipment. The gas lines, instruments, and tubing must be inspected to verify that they do not have any damage from extended use of wet gas. All lines, tubing and instruments with damage must be replaced. If there is not power at locations, generators will have to be set to power the air compressor. One retrofit project can take upwards of 4 months to complete from initial planning to full implementation.

As mentioned previously, there is a 3-year phase-in precedent that has been established for the oil and gas sector, which we believe is the minimum timing required for an appropriate phase-in of the pneumatic controller standard at existing locations. A more appropriate time period, given all of the existing sites in the U.S. and the implementation aspects outlined above, would be 5 years from the finalized rules/guidelines.

2.12 EPA must confirm that emergency shutdown valves or devices are not considered pneumatic devices.

In Section XI.C.1 of the preamble (86 FR 63179), EPA is soliciting comment on whether owners/operators believe that maintaining an exemption based on functional need similar to those finalized in NSPS OOOO and OOOOa is appropriate, and if so, why.

Emergency shutdown devices (ESDs) should remain exempt from the proposed pneumatic controller requirements. An ESD is designed to minimize consequences of emergency situations and will only emit in certain isolated circumstances, such as if a well must be shut in. A large change in pressure is required to actuate an ESD, which may not be deliverable in a sufficient time by a compressed air or electric controller. Furthermore, if power is lost, these devices must still be able to function. ESDs are rarely activated, and their emissions impact is minimal, but their functional need is necessary and critical to safe operations. We also note that both the current version of the proposed rule in New Mexico and finalized regulations in Colorado offer similar exemptions for ESDs.

2.13 The pneumatic controller requirements should be limited to stationary sources.

Pneumatic controllers located on temporary or portable equipment should be allowed to operate as low-bleed or intermittent as needed for proper functioning of the temporary equipment. Connecting temporary controllers into the grid or routing to a combustion device requires significant engineering design, if these options are even available. Non-emitting requirements are not justified for short term controller usage related to a non-stationary source, and exemption of controllers on temporary equipment is consistent with state regulations proposed in New Mexico[20] and finalized in Colorado[21]. EPA should also make it clear that the requirements for pneumatic controllers are not applicable during drilling or completion.

3.0 APPENDIX K PROTOCOL FOR USE AT REFINERIES AND GAS PROCESSING PLANTS

It is API's understanding that the proposed Appendix K protocol was intended to streamline use of optical gas imaging (OGI) technology at refineries and other similar large process facilities such as gas processing plants, as an alternate to M21. In this regard, API supports EPA's development of Appendix K as the ability to use OGI technology provides flexibility and the potential to reduce equipment leak emissions at a lower cost than traditional methodologies.

However, API believes significant modifications to the proposed Appendix K are necessary before it could effectively be implemented for use across downstream oil and gas facilities, gas processing plants, or other process industries. API's recommended changes are intended to proactively address concerns that:

1) the proposed requirements will result in difficulty in finding and retaining adequate numbers of qualified senior OGI operators;
2) the monitoring, training and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and
3) the ownership of various requirements, particularly the recordkeeping requirements, are unclear and unnecessarily burdensome.

API's recommended changes also aim to make the Appendix K requirements more straightforward and efficient. Our recommended modifications to Appendix K are detailed in Attachment A and a suggested redline of Appendix K is provided in Attachment B.

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[20] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

[21] https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view

4.0 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

4.1 Appendix K is inappropriate for use at production facilities, gathering and boosting compressor stations, and transmission compressor stations. OGI monitoring protocols for these facilities should continue to be based on NSPS OOOOa standards.

Appendix K is inappropriate and should not be required for upstream well sites, centralized production facilities, gathering and boosting compressor stations, and transmission compressor stations given. It is impractical for operators to implement the detailed and unnecessarily time-consuming requirements of Appendix K given the hundreds to thousands of well sites and compressor stations to monitor, the geographic dispersion of these facilities and the lack of on-site resources.

Key differences between production facilities and compressor stations versus refineries and gas plants include:

- **Upstream and midstream facilities are smaller, less complex, and have fewer regulated emission components.** A typical well pad size is up to a few acres versus up to thousands of acres for a refinery and well sites contain tens to hundreds of components versus tens of thousands of components at a refinery.

- **There are many more well sites and compressor stations.** There are hundreds of thousands of well sites and compressor stations in the U.S. versus approximately 129 refineries and approximately 500 gas plants.

- **Most new and existing well sites, centralized production facilities, and compressor stations are unmanned sites.** Additionally, these sites are often in remote locations**.** Refineries and gas plants have onsite LDAR personnel.

The following elements of Appendix K make it impractical to implement at upstream and midstream facilities other than gas plants.

- **Appendix K does not appear to support all potential OGI camera deployment platforms, such as drones or fixed continuous monitoring cameras, through its frequent use of the term "handheld".** Current NSPS OOOOa requirements allow a variety of OGI deployment platforms. EPA has also not demonstrated why a different OGI camera deployment would affect the ability of the OGI camera to detect and therefore require development of a separate operating envelope for each OGI camera deployment platform.
- **The lack of in-house personnel that qualify under the currently proposed Appendix K training requirements may force operators to rely on third-party contractors.** A reliance on third-party contractors could result in more emissions from delays in completing leak repairs, given a third-party contractor may not be trained or allowed by the operator to attempt an immediate leak repair. Under NSPS OOOOa programs, some companies' in-house OGI camera operators are allowed to make a first repair attempt upon leak detection.

- **The OGI camera performance specifications in Appendix K are different from those in NSPS OOOOa, reflecting the differences in the two types of sources these two methodologies address.** A comparison of these requirements is presented in the following table.

Appendix K	NSPS OOOOa
An OGI camera meeting the following specifications is required: The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition.	Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.
An OGI camera meeting the following specifications is required: The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr) and butane emissions of 18.5 g/hr at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less.	Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr from a quarter inch diameter orifice.

EPA has not demonstrated that these more stringent requirements are more effective at detecting leaks at well sites, centralized production facilities, and compressor stations. NSPS OOOOa camera specifications have been demonstrated as feasible by EPA testing and in the field. Existing cameras have not been tested and certified to meet the proposed Appendix K specifications. These more stringent Appendix K requirements will require retesting of existing OGI cameras and if the camera does not meet these requirements, require operators to purchase a new OGI camera, which is an additional cost not considered in EPA's cost analysis.

- **The "operating envelope" in Appendix K adds impractical requirements for viewing distance, delta-T, and wind speeds beyond NSPS OOOOa requirements.** NSPS OOOOa already requires procedures for *"determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained", "how the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions", and "determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold."*[22] The Appendix K operating envelope requirements are overly burdensome and may not result in

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[22] 40 CFR 60.5397a(c)(7)

more effective OGI surveys; the current NSPS OOOOa requirements allow the flexibility to conduct effective OGI surveys under the variety of conditions encountered at well sites, centralized production facilities, and compressor stations.

- **The dwell time and break requirements in Appendix K are overly complicated, particularly for well sites, centralized production facilities, and compressor stations, where the density of fugitive emission components (number of components to view in each area) is less than for a refinery or gas plant.** These dwell time and break requirements would double or triple the time required for an OGI survey and have not been demonstrated to be more effective at detecting leaks. One company estimates that 40 or more hours would be needed to conduct an OGI survey of a single site following the Appendix K requirements. Unnecessarily long dwell times result in inefficient emission reductions and take time and resources away from other compliance activities with a greater environmental benefit. Furthermore, prescriptive dwell time is unnecessary and inefficient as an experienced camera operator will determine dwell time based on the circumstances that are occurring at the facility. Some components may require an extended dwell time, while other components may need less.

- **The 10-second video clips of leaks and tagging of leaking components required by Appendix K are overly burdensome to demonstrate compliance compared with the NSPS OOOOa requirement.** NSPS OOOOa requires that *"For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component, or the component must be tagged during the monitoring survey when the fugitives were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture)."*[23] EPA did not consider the additional cost of data storage for the 10-second video clips for a minimum of five years compared to a digital photograph. A digital photograph allows for identification of leaking components without tagging, which may not always be possible for elevated components or components in sour gas service due to safety considerations.

For these reasons noted above, API recommends that OGI requirements for new and existing well sites, centralized production facilities, and compressor stations be based on NSPS OOOOa requirements, not Appendix K.

4.2 EPA could strengthen standards finalized in NSPS OOOOa for using OGI in the production and transmission sectors and not apply the requirements in Appendix K.

As described in Comment 4.1, the provisions proposed in Appendix K are impractical for incorporation at upstream production facilities, gathering and boosting compressor stations, and transmission

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[23] 40 CFR 60.5397a (h)(4)(ii)

compressor stations and would make the use of OGI for leak detection technically impractical and result in inefficient emissions reductions. Operators have been performing OGI surveys at new or modified well sites and compressor stations according to NSPS OOOOa requirements since September 2015. As proposed, Appendix K goes beyond the current NSPS OOOOa requirements concerning performance specifications, “operating envelope”, survey time, and records for leaking components and is impractical for operators to implement given the hundreds to thousands of well sites and compressor stations to monitor and the geographic dispersion of these facilities. Therefore, API urges EPA to retain NSPS OOOOa standards in the proposed regulatory text for NSPS OOOOb and EG OOOOc rather than applying the requirements of Appendix K for these sectors.

The NSPS OOOOa standards for OGI surveys could be strengthened within the NSPS OOOOb and EG OOOOc language, especially with respect to training for OGI camera operators. To help address this concern, we offer the following suggested OGI requirements for the upstream, gathering and boosting, and transmission sectors based on current NSPS OOOOa language in 40 CFR 60.5397a(c)(iv):

> *What fugitive emissions VOC and methane standards apply to the affected facility which is the collection of fugitive emissions components at a well site or centralized production facility and the affected facility which is the collection of fugitive emissions components at a compressor station?*
>
> *[text omitted for brevity]*
>
> *(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.*
>
> *[text omitted for brevity]*
>
> *(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.*
>
> *[text omitted for brevity]*
>
> *(vi) Training and experience needed prior to performing surveys. At a minimum, training and experience must include the elements in paragraphs (c)(7)(vi)(A) through (C) of this section.*
>
> *(A) Initial classroom or computer-based training including the items specified in paragraphs (c)(7)(v)(A)(1) through (8) of this section.*
>
> *(1) Key fundamental concepts of the optical gas imaging equipment technology, such as the types of images the equipment is capable of visualizing and the technology basis (theory) behind this capability.*
>
> *(2) Parameters that can affect image detection (e.g., wind speed, temperature, distance, background, and potential interferences).*

(3) Description of the components to be surveyed and example imagery of the various types of leaks that can be expected.

(4) Calibration, operating, and maintenance instructions for the optical gas imaging equipment used at the facility.

(5) Procedures for performing the monitoring survey according to the site monitoring plan, including the daily verification check; how to ensure the monitoring survey is performed only when the conditions in the field are within the established operating envelope; the number of angles a component or set of components should be imaged from; how long to dwell on the scene before changing the angle, distance, and/or focus; how to improve the background visualization; the procedure for ensuring that all regulated components are visualized; and documenting surveys.

(6) Recordkeeping requirements [assuming consistent with NSPS OOOOa streamlined improvements]

(7) Common mistakes and best practices.

(8) Discussion on the regulatory requirements related to leak detection that are relevant to the facility's optical gas imaging monitoring efforts.

(B) A minimum of 24 hours of surveys under the supervision of an experienced optical gas imaging equipment operator.

(C) Classroom or computer-based training refresher should be conducted no less than every three years. This refresher can be shorter in duration than the initial classroom or computer-based training but must cover all the salient points necessary to operate the equipment (e.g., performing surveys according to the monitoring plan, best practices, discussion of lessons learned throughout the year).

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

4.3 With our recommended changes regarding Appendix K applicability, API supports EPA's co-proposal applicability thresholds and frequencies for OGI monitoring at well sites and supports quarterly monitoring at compressor stations.

For new and existing locations, EPA has proposed the following OGI monitoring frequencies based on the site's potential to emit (PTE) for methane as summarized below:

Site Methane PTE	Co-Proposal Monitoring Frequency
> 0 to <3 tpy	One time
≥ 3 to <8 tpy	Semi-annual
≥ 8 tpy	Quarterly

API is supportive of EPA's co-proposal thresholds and frequency for well sites and centralized production facilities contingent on our recommendations related to the prospective application of Appendix K to these types of facilities.

4.4 The baseline emission calculation for site PTE should be streamlined.

EPA's proposal that site methane PTE calculation updates be required "every time equipment is added to or removed from the site" is too broad and would be overly burdensome since operators would constantly track equipment and perform calculation updates for hundreds to thousands of sites.

As proposed, well site operators must recalculate baseline emissions (which are comprised of a combination of population-based components and controlled storage tank emissions) whenever equipment is added or removed from the site without regard to whether the change results in increased emissions. This appears to convert this fugitive emission requirement into a site-specific inventory requirement. As such, the proposal is inappropriate and has not been demonstrated to be necessary for implementation of the proposed requirement.

Recalculation of baseline emissions is not warranted where equipment is removed because equipment removal will result at best in fewer emissions and at worst in no emissions change. Further, requiring baseline emissions recalculation each time equipment is added to a well site will require onerous tracking of facility changes with little or no environmental benefit. For example, adding one fugitive component to a facility would have no meaningful or significant change to the well site's potential fugitive emissions, yet EPA proposes this change warrants recalculation of baseline emissions. Further, EPA's approach assumes, without basis, that any addition of equipment will result in increased potential fugitive emissions (and specifically in increased potential fugitive emissions with the potential to result in a different inspection frequency).

Under the proposal (i.e., requiring inspections for facilities with baseline emissions above 3 tpy), in very few instances would changes at the facility result in a change in monitoring frequency. Even under the co-proposal (with an additional tier between 3 and 8 tpy), there are limited circumstances when changes at the facility would result in a change in the frequency of inspections. Baseline emissions recalculation should be required only for the qualifying modification events based on the NSPS OOOOa definitions of modification for fugitive emission monitoring per 40 CFR 60.5365a(i)(3) and (i)(4).

For well sites in the most frequent inspection frequency tier, EPA should not require baseline emissions recalculation because no increase in emissions will result in more stringent requirements. If an operator elects to conduct a recalculation to determine if they can reduce inspection frequencies, then operators may elect to do so.

The following includes additional clarifying improvements for when and how to assess the site PTE calculation.

- There must be adequate time to perform initial site PTE calculations at both new and existing locations and to phase-in the initial monitoring survey. These are new calculation assessments and larger operators will have hundreds to thousands of calculations to manage, document, and plan for monitoring. Adequate time following a qualifying modification event must also be provided for updating the site PTE.
- Operators should have the ability to opt-in to quarterly monitoring without any requirement to calculate site methane PTE.
- For obtaining more accurate site emission estimates, operators should be able to use automation, measurement, or state approved emission factors in addition to the specified method described by EPA in this proposal.
- Since OGI detects leaks, but does not measure leaks, EPA must make it clear that sites with emissions less than 3 tpy conduct the one-time leak survey and not be required to reassess the emission evaluation unless there is a qualifying modification event.
- The PTE calculations should be limited to stationary sources. The addition or removal of temporary equipment should not require updated site methane PTE calculations.
- The site PTE calculation should only include controlled storage tanks.

4.5 EPA's cost analysis erroneously assumes operators would not purchase an OGI camera.

As API pointed out in our December 4, 2015 comment letter on proposed NSPS OOOOa[24], EPA continues to exclude the cost of an OGI camera within the cost benefit analysis and assumes operators will only rely on third-party contractors to perform OGI monitoring. This incorrect assumption must be re-evaluated by EPA. As we stated in 2015, API survey responses collected by a third-party ranged from $90,000-$100,000 for an OGI camera. A conservative assumption would be to include the costs for at least a single OGI camera. Most companies own and operate numerous cameras because it takes a team of LDAR technicians to implement and manage an OGI monitoring program across hundreds to thousands of sites.

We also note that EPA failed to consider any additional administrative burden associated with updated requirements described in the proposed Appendix K, which would be significant.

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[24] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776)

4.6 The process for assessing the cause of equipment malfunctions and operational upsets should be streamlined with appropriate completion and reporting schedules.

EPA's proposal requires that an owner or operator must conduct a "root cause analysis" in the case of "a malfunction or operational upset of a control device or the equipment itself, where emissions are not expected to occur if the equipment is operating in compliance with the standards of the rule"(e.g., malfunctioning pneumatic controllers, unintentional gas carry through, or venting from covers and openings on controlled storage vessels) and also where an alternative screening event identifies a "large emissions event."

The specific term "root cause analysis" has other meanings in various regulations and in the oil and gas industry. Instead of using the term directly within NSPS OOOOb and EG OOOOc, we suggest the following description be used in its place as it targets what information and action should occur during the analysis:

> *"Identify the primary cause, and any other contributing cause(s), of a malfunction or operational upset of a control device or the equipment itself".*

We also suggest EPA streamline the recordkeeping and reporting of information related to the assessment.

4.7 Advanced leak detection technologies should be specified as an alternative BSER.

Using transparent and accepted models, alternate technologies can be demonstrated to be as effective as OGI and M21 in emission reductions and should be considered BSER. API supports EPA's inclusion of an option to utilize alternate methane detection technologies, but changes are needed to provide increased flexibility in their implementation. Discussed below are our suggestions to create a more workable framework.

4.7.1 EPA should create a functional and transparent framework for using alternate leak detection technologies.

API supports development of a framework that drives innovation and lowers the economic hurdles typically experienced with new technologies. Key considerations for such a framework include:

- **A minimum detection threshold of 10 kg/hr restricts operators' flexibility in selecting appropriate alternate technologies.** EPA's proposal arbitrarily sets the alternate technology minimum detection threshold to 10 kg/hr with a corresponding bimonthly survey frequency, coupled with an annual OGI survey. No supporting data are provided to demonstrate that this combination of technologies and frequencies is needed to achieve the desired emission reductions. Some operators are currently using alternate technologies with higher detection thresholds (e.g., 30 kg/hr), and the proposed framework should allow them the flexibility to continue the use of these technologies with an appropriate survey frequency. Conversely, the framework should also include lower detection thresholds and associated lower survey frequencies.

- **API supports the development of a matrix approach for alternate technologies.** For non-continuous technologies, the matrix should prescribe a minimum detection threshold based on a given survey frequency. The minimum detection threshold should be based on modeling (such as, but not limited to, FEAST or LDAR-Sim) that demonstrates that the alternate technology is expected to achieve the required emission reductions. This approach would not specify particular technologies or deployment platforms and would allow for easy use of future technologies so long as they meet the required minimum detection threshold. The proposed matrix could look like the following example.

Minimum Methane Detection Threshold (kg/hr)	Survey Frequency (x per year)
A	3
B	4
C	6

API members look forward to continued engagement with EPA on alternate leak detection technologies and in developing this matrix approach as EPA works towards the supplemental proposal. Our experience with modeling suggests monitoring frequency could be reduced to 4 surveys and one annual OGI inspection.

- **In the interest of transparency, any modeling results and information used to justify a proposed set of alternate technologies/detection thresholds and associated survey frequencies should be publicly available.** For others to evaluate and verify any proposals, it is necessary to have all relevant modeling information, including targeted control efficiencies, data inputs and assumptions. This transparency will be important both for any EPA modeling as well as modeling results submitted to EPA by other stakeholders.

- **The framework should support the use of multiple monitoring technologies for effective combinations of leak detection.** The framework should allow operators to implement one or more technologies to achieve the emission reduction goals. A combination of M21, OGI, and alternate technologies implemented at various frequencies can be as or more effective as a single technology at a given frequency. A matrix like the one above would allow operators to implement any technology that meets the minimum detection threshold for any given survey at the required frequency (i.e., a different technology could be used for each of the required surveys so long as it meets the minimum detection threshold). Separate matrices could also be developed based on a requirement to perform an annual OGI or M21 survey in addition to the screenings with alternate technologies. The frequency and detection threshold matrices would be supported by modeling.

- **The framework should also support the use of continuous monitoring technologies.** Continuous monitoring technologies can detect large leaks in real-time. API members see great promise in continuous/near-continuous methane monitoring technologies and encourage EPA to work with stakeholders to develop a framework that allows for usage of such technologies. Potential elements of the framework could include guidance on the content of an operator's continuous monitoring plan, including information such as types of sensors, modeling, placement of sensors, detection thresholds, downtime, networking/software, data fusion and management, follow-up procedures and QA/QC. To inform development of a proposed framework, EPA should consider hosting a multi-stakeholder workshop(s) prior to release of the formal regulatory text. API members look forward to working with EPA on pathways to developing monitoring programs.

- **A streamlined approval process should be included for future technologies that do not fit the existing framework.** API recognizes the challenges of writing regulations for a variety of alternate technologies and supports the inclusion of a streamlined approval process for alternate methane detection technologies that may not meet the prescribed framework but can be demonstrated to be as effective at reducing emissions. If such a technology is approved for one company, EPA should provide a pathway for other companies to implement this new technology under the same conditions approved, without the administrative burden of repeating an approval process that has already been reviewed and completed by EPA.

- **The proposed 14-day follow-up OGI survey should be focused on the highest emitting non-authorized sources and not be required for all emissions detected with alternate technologies.** The framework should limit follow-up OGI surveys to sites where the source of a persistent leak cannot be identified from the alternate technology screening data or other operational data. Not all emissions are actual persistent leaks. Where the alternate technology or operational data can identify the source of the detected emissions, the operator will evaluate whether the detected emissions represent an event that needs to be repaired or represent authorized emissions from the site. Where the source of an event can be identified by alternate technology or operational data, operators should have the option to not conduct a follow-up OGI survey and instead begin repair attempts. This option will focus operators' time and effort on repairing leaks instead of conducting follow-up OGI surveys to confirm information already provided by the alternate technology or other operational data.

  When required, follow-up OGI surveys should be prioritized for the sites with highest detected emissions; this approach will focus operators' time and effort on the repairs with the greatest environmental benefit. The framework should define clear thresholds for this prioritization of follow-up OGI surveys or repair attempts.

- **Timelines for a follow-up OGI survey or an initial repair attempt should be based on the date that final data (i.e., data that have undergone proper QA/QC procedures by the vendor) from the alternate technology screening are received.** Depending on the number of sites surveyed, final data from an alternate technology screening can be received days to weeks after the date that the actual survey is conducted. Compared to OGI surveys, alternate technology screenings allow operators to survey up to hundreds of sites more quickly and identify and repair large emission events. Although preliminary data from alternate technology screenings can be informative, the final processed data that has undergone proper QA/QC provides the operator more confidence in the results and contains more detail that allows the dataset to be actionable. The timeline to complete the follow-up survey or initial repair attempt should begin on the date that the final data report is received by the operator.

5.0 LEAK DETECTION AND REPAIR AT GAS PROCESSING PLANTS

API generally supports EPA's proposal for bimonthly OGI monitoring for equipment leaks at gas processing plants. We also support retention of NSPS VVa as an alternative monitoring option, as some facilities have compliance obligations through consent decrees or permits or are subject to state or local regulations that require the use of M21. In general, we also support the use of Appendix K for OGI monitoring at gas processing plants with appropriate changes as detailed further in Comment 3.0 and Attachments A and B.

We have additional suggestions to improve the described proposal and address implementation concerns as follows:

- **The proposed bi-monthly OGI monitoring requirements should also apply to closed vent systems and equipment designated with no detectable emissions.** This equipment should be treated like other fugitive emission components similar to the requirements option for quarterly M21 monitoring of pressure relief devices in NSPS OOOO and OOOOa (40 CFR 60.401a5401(b)). The increased frequency of bi-monthly OGI monitoring compared to an annual M21 survey should allow OGI to be as effective as M21 at detecting leaks from this equipment. Bi-monthly OGI monitoring would also decrease costs since a separate M21 program would not be required.

- **EPA should not remove the VOC concentration threshold from the proposed LDAR requirements and should instead propose a similar concentration threshold for methane.** EPA should retain the current 10.0 percent by weight threshold for VOC and add a 1.0 percent by weight threshold for methane. While EPA is correct that a VOC concentration threshold is not an appropriate threshold for determining whether LDAR for methane applies, EPA failed to realize that some streams at a gas processing plant have de minimis concentrations of VOC and methane (e.g., purity ethane, produced water, wastewater). Without appropriate concentration thresholds, equipment with no appreciable amounts of VOC or methane would be subject to LDAR requirements, which API does not believe was EPA's intent with this proposal. Minimum concentration thresholds are especially important if an owner or operator chooses to use M21 since tagging of components are required (along with accounting for and maintaining these tags); monitoring additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with little environmental benefit.

6.0 STORAGE VESSELS

6.1 For completely new surface sites, API supports the proposed 6 tpy VOC threshold for a single storage vessel or tank battery.

API supports EPA's proposed 6 tpy VOC threshold for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. Although not discussed in the proposed rulemaking for NSPS OOOOb, API encourages EPA to retain the current alternate control standard in NSPS OOOOa to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC. In the preamble to the NSPS OOOO revisions dated April 12, 2013[25], EPA noted that removal of control at 4 tpy VOC will reduce emissions from burning more pilot gas than the waste gas being burned. Below are additional considerations regarding control requirements for a single storage vessel or tank battery:

- **As oil production declines, operators may need to replace the original storage vessel or tank battery combustion device with a smaller capacity device.** Applying the same threshold as a single storage vessel to a tank battery means that a control device will be required for a longer duration. This longer control duration and potential additional costs for a smaller replacement control device were not considered in EPA's cost analysis.

- **EPA should allow for an exemption from control requirements due to technical infeasibility if the control device would require supplemental fuel**. This type of exemption has been rationalized by state regulations for storage vessels and tank batteries, such as in Colorado, where there is an exemption from control requirements for tanks if use of a control device would be technically infeasible without supplemental fuel for pilot or other purposes. API recommends that EPA consider such an exemption for NSPS OOOOb and EG OOOOc. The regulatory text for the Colorado exemption is provided for consideration below.

  > *Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.*

6.2 The proposed definition of tank battery should be based on manifolded tanks by liquid line.

EPA's proposed definition of a tank battery is overly complex given the objective of including a tank battery as a storage vessel affected facility. Based on the definition of a "storage tank" in Colorado

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[25] Federal Register Vol. 78, No. 71, 22133-22134

Regulation 7, "manifolded by liquid line" is a simple and clear criterion for defining a group of storage vessels as a tank battery. The Colorado Air Quality Control Commission established a definition for a "storage tank" for Regulation 7 by expanding upon the definition of a storage vessel in NSPS OOOO and OOOOa to include storage vessels manifolded together by liquid line. The other criteria (e.g., physically adjacent, manifolded for vapor transfer) in EPA's proposed definition would cause potential confusion around applicability. We offer a suggested definition of a tank battery based on EPA's proposal language (86 FR 63178) as follows:

> *The EPA proposes to define a tank battery as a group of storage vessels that ~~are physically adjacent and that receive fluids from the same source (e.g., well, process unit, compressor station, or set of wells, process units, or compressor stations) or which~~ are manifolded together for liquid ~~or vapor~~ transfer.*

6.3 The proposed definition for a modification of a tank battery requires additional clarification.

The EPA is proposing to require that the owner or operator recalculate the potential VOC emissions when certain actions occur on an existing tank battery to determine if a modification has occurred. EPA's proposed definition for a modification of a storage vessel or tank battery is inconsistent with NSPS Subpart A and requires additional clarification. Per 40 CFR 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification.

EPA should also clarify whether other individual storage vessels in an existing tank battery remain affected facilities under NSPS OOOO or NSPS OOOOa, as applicable, or become part of the modified tank battery under NSPS OOOOb.

API recommends the following changes:

> "The EPA is proposing that a single storage vessel or tank battery is modified *when physical or operational changes are made to the single storage vessel or tank battery that result in an increase in the potential methane or VOC emissions. Physical or operational changes ~~would be defined~~ include:*
>
> *(1) The addition of a storage vessel, to an existing tank battery;* or
>
> *(2) replacement of a storage vessel, such that the cumulative storage capacity of the existing tank battery increases.~~; and/or~~*
>
> *~~(3) an existing tank battery or single storage vessel that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery)."~~*

6.4 API generally supports EPA's proposal for existing storage tank batteries under EG OOOOc.

API generally supports EPA's proposal for 95 percent emission reduction for existing storage vessels and tank batteries with potential methane emissions of 20 tpy or more under EG OOOOc. That said,

- EPA should provide an exemption from control requirements due to technical infeasibility if the control device would require supplemental fuel.
- One additional consideration for existing storage vessels or tank batteries is the additional cost for control at sites in dry gas plays with produced water storage vessels or tank batteries only. Some of the produced water storage vessels are fiberglass tanks and would have to be replaced with steel tanks to support the installation of a closed vent system and control device due to backpressure. The additional cost for storage vessel replacement was not included in EPA's cost analysis. If capital costs to replace a storage vessels(s) are $20,000 or more this would result in a cost effectiveness of over $1,900 per ton of methane reduced for a combustion control device using EPA's own cost analysis.

6.5 API supports EPA's proposed alternative approach to specify within NSPS OOOOb and OOOOc that storage vessels at well sites and centralized production facilities are subject to requirements in those regulations instead of NSPS K, Ka, or Kb.

As EPA states in its proposal (86 FR 63184), "this alternative approach would eliminate the need for sources to determine if the storage vessel meets the exemption criteria specified in those subparts and instead focus on appropriate controls for the storage vessels based on the location and type of emissions likely present (e.g., flash emissions)." API believes that this approach provides a clearer path for determining regulatory applicability for storage vessels in the production segment. API notes that some storage vessels at production facilities store liquids that do not contain dissolved gases. For those tanks, facilities could still opt to control emissions using a floating roof, as is currently allowed under NSPS OOOOa (40 CFR 60.5395a(b)).

7.0 WELL LIQUIDS UNLOADING OPERATIONS

7.1 API generally supports a work practice standard built around the Best Management Practices approach described by EPA in this proposal.

API generally supports a work practice standard built around the Best Management Practices (BMP) approach described by EPA in this proposal. We support EPA in allowing flexibility for operators to manage and operate their wells based on the engineering needs of the well. As a point of clarification, we note that EPA's discussion of liquids unloading methods in the Technical Support Document to this proposal characterizes several techniques as non-venting techniques. Some of the solutions discussed may minimize emissions from unloading, but not fully eliminate them.

- **Contingent on clarification that these requirements are specific to liquids unloading of gas wells that vent emissions to atmosphere, we support EPA's proposed Option 2.** EPA should confirm that the liquids unloading requirements will apply to gas wells that vent emissions from liquids unloading to atmosphere only. Since EPA's process description in the Technical Support Document for liquids unloading mentions only gas wells, we believe that it was EPA's intent to limit the affected facility for liquids unloading to gas wells only.

- **EPA's proposal for Option 1 is not feasible**. As proposed, Option 1 would require operators to track all unloading events. This would include unloading events that are automated on artificial lift or pump jacks and even those that do not vent any emissions to the atmosphere. We do not support this approach as there is no environmental benefit associated with this Option and it would generate a significant amount of administrative burden.

- **Operators already report the number of liquids unloading events to EPA under the Greenhouse Gas Reporting Program.** In the proposal, EPA has described the reporting information for wells that utilize methods that vent to the atmosphere as including the number of liquids unloading events in an annual report, which is duplicative of other EPA reporting requirements.

- **EPA is correct in allowing flexibility for liquids unloading operations.** Well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective. There are numerous misconceptions about why and how this activity is conducted. The technology options EPA describes in the proposal are designed to remove liquids from a well. Their function is not to reduce emissions resulting from gas that might be entrained in the liquids removed. For some situations a certain technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. Therefore, we support EPA in providing criteria for consideration for inclusion in an operator's BMP, as listed in the proposal and provided below, but not dictating all specific practices:

> *"BMPs would require operators to monitor manual liquids unloading events onsite and to follow procedures that minimize the need to vent emissions during an event. Such as:*
>
> - *having a person on-site during the liquids unloading event to expeditiously end the venting when the liquids have been removed,*
> - *following specific steps that create a differential pressure to minimize the need to vent a well to unload liquids and reducing wellbore pressure as much as possible prior to opening to atmosphere via storage tank,*
> - *unloading through the separator where feasible, and/or*
> - *closing all well head vents to the atmosphere and return of the well to production as soon as practicable."*

- **EPA must clearly define liquids unloading within NSPS OOOOb.** Other well maintenance and workover activities may occur on a well. These activities are distinctly different, require different equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. To address this clarification, we offer the following definition for "Liquids Unloading":

  > *"Liquids Unloading" means the removal of accumulated liquids from the wellbore that reduce or stop natural gas production from natural gas wells. Routine well maintenance activities, including workovers, swabbing, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.*

8.0 ASSOCIATED GAS VENTING FROM OIL WELLS

8.1 API supports elimination of venting from "each oil well that produces associated gas and does not route the gas to a sales line" with additional clarifications.

While EPA's proposal is overly broad in its description, API generally supports and recognizes the environmental benefit of the elimination of venting of associated gas from oil wells that do not currently route gas to a sales line (EPA's proposed option 2). If associated gas cannot feasibly and economically be recovered to a sales line, API supports capturing the gas for a beneficial use or flaring the gas such that 95% control efficiency is achieved.

8.1.1 Special considerations for handling associated gas at wildcat and delineation wells.

EPA did not allow provisions for wildcat or delineation wells in its proposal. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. Like provisions within NSPS OOOOa for well completions, EPA should allow special considerations for handling associated gas at these types of operations. Specifically, any associated gas initially generated from wildcat or delineation wells should be routed to a combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways).

8.1.2 EPA correctly identified that access to a sales line does not equate to availability of a sales line.

API agrees that EPA correctly characterized scenarios *"when gas capture may not be feasible, such as when there is no gas gathering pipeline to tie into, the gas gathering pipeline may be at capacity, or a compressor station or gas processing plant downstream may be off-line, thus closing in the gas gathering pipeline."* (86 FR 63237).

To further elaborate, access to a sales pipeline is based on numerous criteria that can be out of the control of the well operator. A few challenges (including those above) have been summarized below for EPA's awareness and consideration:

- **Topography:** Mountains, rivers, lakes, etc. can limit a producer's ability to connect into a pipeline.

- **A contractual right to flow into the gas gathering system must be agreed to with the company that owns the gathering line**. In most cases, the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added and if the quality of gas meets their required specifications.[26]

- **Necessary permits and ROW must be obtained for the pipeline from the well site to the natural gas gathering system.** Permits and ROW are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary ROW can be difficult and may require a court order. On certain federal lands, operators have been required by BLM in recent years to reroute proposed pipelines or to adjust installation techniques, which significantly delays the completion of gathering systems. On private lands, individual landowners may deny rights.

- **The natural gas must meet the specifications of the natural gas gathering line.** Contracts with the gathering company include specifications for entering the gas gathering line, such as allowable concentrations of inert gases such as carbon dioxide or nitrogen, and hydrogen sulfide. The natural gas gathering system owner ultimately controls when an operator can send gas to sales.

- **The natural gas gathering line must be operational.** Natural gas gathering lines can be temporarily down or unavailable for a multitude of reasons including, but not limited to, compressor maintenance or repair, line maintenance, line inspection, a gas plant being shut down, or temporary reductions in capacity. In some instances, a well will be connected to sales, but if a compressor station has an emergency upset, then the wells tied into the gathering system will not be able to send gas through the pipeline. These instances are often episodic, temporary, and not in the well operator's control.

Due to the various challenges described, EPA is correct in allowing the beneficial reuse of gas onsite or combusting the gas where accessing the pipeline is not available or technically feasible.

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[26] Additionally, capacity issues could exist even in cases where the production company is also responsible for the gathering system.

8.2 EPA underestimated the cost of installing a flare in its cost benefit analysis, using a value significantly lower than EPA estimates for flares for other affected sources.

EPA must re-evaluate the cost effectiveness using more relevant cost information that is consistent with how flares are costed for other emission sources. Throughout the Technical Support Document for this proposed rule, EPA has assumed various costs with respect to installing a flare or other combustion device.

In review of EPA's cost evaluation data for associated gas from oil wells, EPA assumed that a flare would cost only $5,700. This value significantly underrepresents actual costs experienced by operators. A more representative cost for installing a flare suitable to control associated gas would be $100,579, based on the average costs EPA uses for analyzing storage vessel controls. To obtain an average cost of $100,579 per flare, we reviewed the direct capital costs associated with calculation sheets issued by EPA[27] as listed in the following table:

EPA Flares Calc Sheet MP1 **Small Flare**	**EPA Flares Calc Sheet MP2** **Medium Flare**	**EPA Flares Calc Sheet MP-G** **Large Flare**	**EPA Flares Calc Sheet MP-H** **Largest Flare**	**EPA Estimated Average Costs for Various Sized Flares**
$79,352	$84,761	$92,874	$145,328	**$100,579**

Note that we did not include the costs from EPA's Workbook *'MP1 Plus Monitors.xlsx'* as this would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the proposal. If EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA's cost analysis.

9.0 OTHER PROPOSED STANDARDS

9.1 Pneumatic Pumps

We generally support the pneumatic pump provisions as described in the proposal for NSPS OOOOb and EG OOOOc.

As noted in our December 4, 2015[28], comments on the proposed Subpart OOOOa[29], there are numerous implications for routing a piston pump to a control device or VRU and we continue to support EPA in excluding piston pumps from EG OOOOc.

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[27] https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0039

[28] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776)

[29] https://www.regulations.gov/comment/EPA-HQ-OAR-2010-0505-6884

9.2 Reciprocating Compressors

9.2.1 The applicability of the compressor standards requires clarification.

EPA should clarify the applicability of compressor standards to well sites, as the proposal is unclear. The definition proposed for central production facility may extend applicability to compressors located at well sites, which have historically been exempt from the compressor standards. As EPA states they have not updated their cost analyses with new information with respect to well sites, we believe extending applicability to well sites is not EPA's intent.

EPA should also provide clarification that temporary compressors (i.e., those onsite for less than 12 months) are not subject to these provisions. Additionally, EPA should consider whether it is appropriate to establish applicability thresholds based on compressor size, stages, or gas throughput or exclude compressors used in specific applications (e.g., casing, injection, gas lift compressors).

9.2.2 EPA should provide additional flexibility for addressing rod packing leaks.

EPA should provide flexibility by allowing operators the option to change out rod packing based on hours of operation/fixed frequency, like the current requirements in NSPS OOOO and OOOOa, or to perform the newly proposed annual monitoring and replacement of rod packing if a leak is identified.

Another potential option to streamline the monitoring burden is to allow operators to screen for leaks during annual OGI assessments and only perform measurement of the rod packing if it is identified as leaking during the OGI screening. This option has been approved under the Greenhouse Gas Reporting Program for gas processing and transmission facilities under 40 CFR Part 98, subpart W.

9.2.3 Proposed packing leak threshold and logistical monitoring concerns.

EPA should re-evaluate the designated leak threshold of >2 scfm per cylinder, as it may not be appropriate for all applications. Appropriate leak thresholds vary based upon the individual compressor type, size, and operating conditions. Our preliminary review indicates the 2 scfm/cylinder threshold proposed by EPA is an extension of regulations finalized in California[30]. In review of supporting documentation provided by the California Air Resources Board, it seems this threshold for rod packing replacement is based on data from a single vendor's alarm set point.[31] Publicly available data from another compressor manufacturer[32,33] indicates "expected packing leakage for typical alarm points is between 1.7 and 3.4 scfm", and experience from some API members indicates some maintenance may

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[30] https://ww2.arb.ca.gov/resources/documents/oil-and-gas-regulation

[31] See pages 109 -110 of the Initial Restatement of Reasoning, May 31, 2016. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf

[32] https://www.arielcorp.com/company/newsroom/compressor-emissions-reduction-technology.html

[33] https://www.arielcorp.com/application_manual/Arieldb.htm#Packing_Leakage.htm?Highlight=packing%20leakage

be conducted up to a 4 scfm threshold per manufacturer recommendations. Therefore, a more comprehensive review of compressor manufacturer information is required for determining an appropriate threshold for rod packing replacement under NSPS OOOOb and EG OOOOc.

Clarification is also needed on how the annual monitoring standard is applied for certain packing vent configurations and systems. For example, if an operator uses a continuous meter on a rod packing vent, how would compliance be demonstrated against the annual measurement? How will replacing the packing due to a different reason/program affect the annual monitoring window? When packing vents are manifolded together, is the standard determined by multiplying the leak threshold by the number of cylinders?

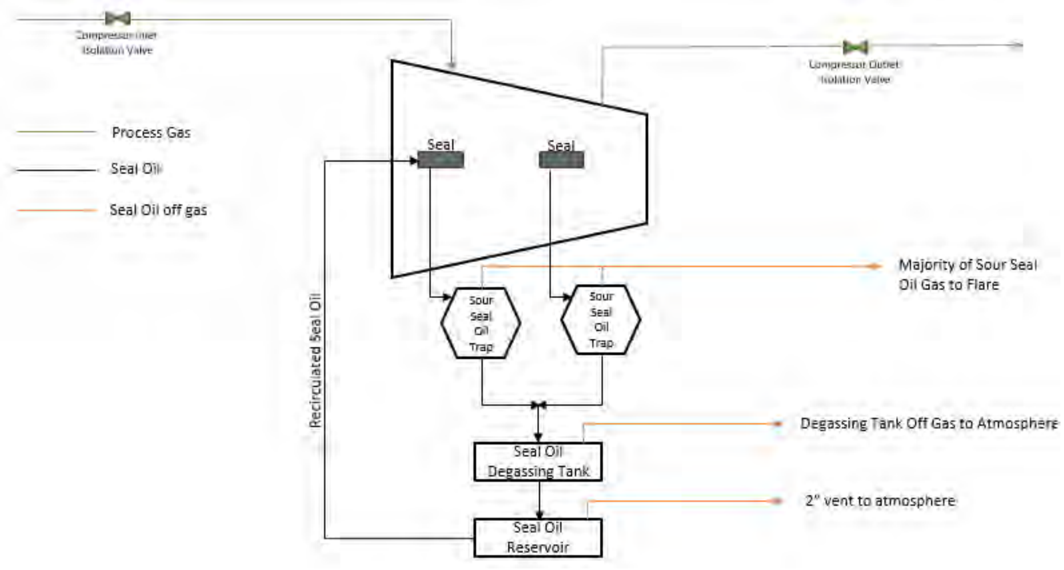
There are also practical considerations for how and when to conduct measurements. These types of concerns for implementation are well documented within subpart W for natural gas plants and transmission compressor stations. For example, the requirements in 40 CFR Part 98, Subpart W, only require rod packing measurements when a compressor is in operating mode at the time the measurement is set to occur (i.e., when the measurement team arrives onsite). Additionally, equipment modifications may be required to facilitate measurement of rod packing vents (e.g., adding an accessible port in vent piping), and adequate implementation time must be provided.

9.3 Wet Seal Centrifugal Compressors

9.3.1 Considerations for Compressors on the Alaskan North Slope

On the Alaska North Slope (ANS) there is not a market for natural gas sales. The majority of gas that is produced with the oil is separated and then compressed (using large wet seal compressors) to be reinjected back down hole for conservation and enhanced oil recovery. The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.

Wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures the vast majority of the gas by volume then routes that gas to a flare. The ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum/tank, where any remaining entrained gas breaks out and is vented to atmosphere. The following figure depicts this process:



In 2010, EPA's Natural Gas Star program[34,35], in conjunction with BP, conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis concluded that the sour seal oil degassing design employed on the ANS has greater than 99% emission control. That level of emission control is equivalent to a dry gas seal system.

Since dry gas seal systems are not subject to these proposed rules (due to their low leak rate), and the ANS wet seal degassing system design has demonstrated equivalence to dry gas seal systems, wet seal degassing designs employing sour seal oil traps should also not be subject to the rule. The two systems are equivalent from a venting perspective and should receive similar treatment under the regulations.

10.0 OTHER COMMENTS

10.1 Orphan and Unplugged Wells

The information below is provided to address EPA's queries concerning idle/abandoned and orphaned wells.

10.1.1 EPA does not have authority under CAA § 111 to impose financial assurance requirements.

EPA explains that it "is soliciting comment for potential NSPS and EG to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged

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[34] https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf

[35] https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf

ineffectively." 86 Fed. Reg. at 63240. Among other measures, EPA suggests that it "could require owners or operators to submit a closure plan describing when and how the well would be closed and to demonstrate whether the owner or operator has the financial capacity to continue to demonstrate compliance with the rules until the well is closed and to carry out any required closure procedures per the rule." *Id.* at 63241.

For the reasons discussed below, API believes that emissions from abandoned wells are not as great as EPA suggests and that issues related to well closure are more appropriately addressed by the states and BLM. Should EPA decide to further address this issue in the upcoming supplemental proposal however, the possibility of requiring a demonstration of financial capacity should not be a part of that proposed rule given EPA has no authority under the Clean Air Act to impose a financial assurance requirement.

EPA and states have authority under the CAA to establish "standards of performance" applicable to affected facilities. *See* CAA §§ 111(b)(1)(B) and (d)(1). The term "standard of performance" is defined in CAA § 111(a)(1) to mean, in relevant part, "a standard for emissions of air pollutants" – *i.e.*, an emissions limitation or comparable requirement (such as an equipment or work practice standard). This is reinforced by the more broadly applicable CAA § 302(l) definition of "standard of performance," which defines that term to mean "a requirement of continuous emissions reduction." Neither of these definitions can reasonably be construed as authorizing EPA to issue financial assurance requirements for affected facilities.

In conjunction with the obligation of EPA and states to issue standards of performance, the Clean Air Act provides authority to establish corresponding compliance assurance measures, such as monitoring, recordkeeping, and reporting requirements. CAA § 114(a). However, a financial assurance requirement is fundamentally different in kind from such measures. Monitoring, recordkeeping, and reporting are designed to provide information necessary to determine applicability and demonstrate compliance with a standard of performance. In contrast, a financial assurance requirement is designed to make sure enough money is available to implement a standard of performance at some point in the future. Nowhere in the CAA is there express or implied authority for EPA to establish such a requirement.

Notably, in instances where Congress wants EPA to require financial assurance, authorization has been explicit. *See, e.g.,* 42 U.S.C. § 6924(a)(6) (Requiring EPA to establish rules for treatment, storage, and disposal facilities regulated under the Resource Conservation and Recovery Act to ensure "the maintenance of operation of such facilities and requiring such additional qualifications as to ownership, continuity of operation, training for personnel, and financial responsibility (including financial responsibility for corrective action) as may be necessary or desirable."). The absence of such an express provision in the Clean Air Act cannot be construed as a grant of authority.

10.1.2 Substantial progress on – and additional information concerning - idle/orphaned well clean up may be expected based on recent federal funding.

Passed as part of the Infrastructure and Investment Jobs Act of 2021, the REGROW Act provides funding to invest in the environment, and a skilled workforce. This includes $4.275 billion for orphaned well clean up on states and private lands, $400 million for orphaned well cleanup on public and tribal lands, and $32 million for related research, development, and implementation.[36] Any applications from states for these grant funds can help provide more concrete numbers. Additionally, any of these funds that are distributed as grants to state agencies may contain additional environmental and reporting obligations, which, when viewed in the proper context, may lend additional light to this issue. These recent developments further minimize the need or justification for EPA to expand its regulatory efforts on this topic to encompass orphan wells.

10.1.3 Further granularity on idle/orphaned wells was provided in December 2021, when the Intergovernmental Oil and Gas Compact Commission (IOGCC) released an update of its 2019 report on idle and orphaned wells to include 2019 – 2020 data. Because IOGCC's work is based on over 30 years of review, EPA should consider this information carefully before determining a course of action.

The Interstate Oil and Gas Compact Commission (IOGCC) is a multi-state government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. As an organization, IOGCC is committed to continuing to support the states and provinces in their efforts to continually improve their idle and orphan well programs and also to providing a forum for information-sharing of effective tools and strategies. IOGCC has also been included in the DOI MOU[37] for the recently enacted grant program referenced above.

Across decades of studying idle and orphaned wells, the IOGCC has published reports on the issue in 1992, 1996, 2000, 2008, and 2019.[38] A new report covering data from 2019 and 2020 was published in December 2021.[39] As these reports show, the IOGCC has been following this issue for 30 years. API encourages EPA and other agencies interested in regulations on this topic to review the report in detail.

The 2021 IOGCC report features survey responses from 32 IOGCC member and associate member states and five Canadian providences. It includes data from 2018 – 2020 and concerns the number of both idle and orphan wells, well plugging and site restoration costs, and remediation strategies (including regulatory tools and funding sources used to ensure idle wells are properly maintained).

The IOGCC report also provides helpful clarification of terminology, which is often misused in idle/orphan well conversations. We encourage EPA to align its terminology with the terminology used by IOGCC to reduce confusion:

- ***Idle Wells.*** The IOGCC defines idle wells as "wells that have not been plugged and are not producing, injecting, or otherwise being used for their intended purposes."[40] Similarly, they note that "[M]any idle wells have potential for oil or gas production or associated uses."[41] The future

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[36] REGROW Act Infrastructure and Investment Jobs Act of 2021, H.R. 3684, 117th Congress (2021).

[37] Orphan Well MOU (doi.gov)

[38] Interstate Oil and Gas Compact Commission (IOGCC), Idle and Orphan Oil and Gas Wells, (2019).

[39] Interstate Oil and Gas Compact Commission (IOGCC) Idle and Orphan Oil and Gas Wells, (2021).

[40] IOGCC *(*2021) at 2.

[41] *Id.*

outcome for an idled well could be that it is brought into production, plugged, or converted to an injection well for enhanced oil recovery or for disposal. Most regulatory agencies set a timeline and requirements (whether statutory, by rule, or by specific written approval) for how long a well may remain idled before it must be plugged. The total number of approved idle wells reported by the states as of December 31, 2020, is 231,287, which is 14 percent of the total number of documented wells that have been drilled but not plugged.[42] Notably, despite including 4 more states in the 2021 report, this is down over 20 percent from the IOGCC's 2019 figures, which featured "a total number of approved idle wells is 294,743, which is 15.6 percent of the total number of documented wells that have been drilled and not plugged."[43] In the three years covered by this report, operators plugged 62,463 wells in the states[44].

- ***Orphan Wells.*** The IOGCC defines orphan wells as "idle wells for which the operator is unknown or insolvent. Most states and provinces have inventories of documented orphan wells and prioritize orphan wells for plugging according to risk. As of December 31, 2020, the states reported a total of 92,198 documented orphan wells, and the provinces reported a total of 5,015 documented orphan wells. In the states, the number of documented orphan wells increased by 50 percent from 2018 to 2020, due primarily to the efforts of states to document these wells through investigation and verification of the status of wells and their operators. In the three-year period from 2018 through 2020, the states plugged 9,774 orphan wells and the provinces plugged 4,930. In total through 2020, the states have plugged over 78,000 orphan wells and the provinces almost 6,300."[45]

- ***Undocumented Wells.*** The IOGCC identified undocumented wells as a category for further work, noting that these are mostly a historical concern. Unverified estimates "do not convey a reliable picture of the actual number or the potential associated risk. The estimates are by their nature imprecise, and many undocumented wells may not constitute a significant risk to the environment or public health and safety."[46] It is important to understand that the lack of plugging documentation for these wells does not mean they were never plugged and the lack of the locations for such wells make any action or quantifications difficult. Thanks to modern record-keeping and regulation it is uncommon to be unable to identify the owner or operator a well. The majority of orphaned or undocumented wells occur as a result of development before the 1950s. For example, Pennsylvania is estimated to have the largest number of orphaned wells in the country, and the Pennsylvania Department of Environmental Protection explains, "Since the first commercial oil well was drilled in Pennsylvania in 1859, it is estimated that 300,000 oil and gas wells have been drilled in the state. Only since 1956 has Pennsylvania been permitting

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[42] *Id.*

[43] IOGCC *(*2019)at 5.

[44] IOGCC (2021) at 2.

[45] *Id.*

[46] Id at 3.

new drilling operations, and not until 1985 were oil and gas operators required to register old wells."[47]

10.1.4 EPA should not create duplicative and unnecessary regulations, which may conflict with specific rules promulgated by the states and BLM to address orphaned, idle, and abandoned wells.

Oversight for idle, orphan, and historical undocumented orphan wells is state-specific according to local regulatory programs, most of which include requirements for wells to remain idle and established prioritization systems for known orphaned wells. Additionally, most states already have funding mechanisms for plugging orphan wells, which are supported by industry taxes and fees. To avoid duplication or unintended consequences, the EPA should carefully examine these diverse programs and funding mechanisms prior to any additional regulatory work.

As an example of continuous improvement within the applicable states, over half of the states and provinces participating in the IOGCC survey reported improvements in their idle and orphan well programs between the IOGCC reports in 2008 and 2021. In 2019, the IOGCC noted that these included "process improvements in communication, collaboration, contracting, third-party plugging, compliance assurance, data systems, and bonding; implementation of program efficiencies; increases in staffing and funding; and application of Geographic Information System (GIS) and drone technologies. Through the decades, the states and provinces have made considerable progress in plugging orphan wells and reducing the likelihood of additional wells becoming orphaned. They have also continued to evaluate and adjust their financial assurance requirements and their plugging funds to ensure there will be funds available for well plugging and site restoration."[48]

The 2021 IOGCC report expanded its description of regulatory strategies used by the various states which include, "requirements, such as periodic mechanical integrity testing, that must be met for wells to remain idle beyond a specified time. These requirements may be set by statute, rule, or written approval. Most states and provinces also require financial assurance to provide money for plugging and restoration if the operator defaults. Financial assurance instruments include cash deposits, certificates of deposit, financial statements, irrevocable letters of credit, security interests, and surety or performance bonds. The types accepted and amounts required vary considerably among the states and provinces. The participating states all provide for single-well and blanket coverage, and the participating provinces provide for either single-well or blanket coverage, or both. The amounts may be uniform for all wells, or they may be based on the depth, location, type, or status of well or case-by-case evaluations. To supplement the funds provided through financial assurance instruments, most states and provinces have established funds dedicated to plugging orphan wells. Money for these funds comes primarily from taxes, fees, or other assessments on the oil and gas industry. Nineteen states and provinces reported on innovations and advancements in their idle and orphan well programs. Some

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[47] DEP Quote Pennsylvania Department of Environmental Protection, "The Well Plugging Program", available online at https://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/AbandonedOrphanWells/WellPluggingProgram.pdf

[48] IOGCC (2019) at 21.

have added staff, improved their data management systems, and streamlined their contract management processes. Some have adopted new idle well requirements, such as requirements to provide additional financial assurance, demonstrate well integrity, justify keeping wells in idle status, or limit the percentage of wells an operator may hold in idle status. Increasingly, states and provinces are using Geographic Information Systems (GIS) and drone technologies to find orphan wells. They are also collaborating with operators and landowners to address idle and orphan wells and using grant programs, economic stimulus funds, and third-party partnerships for orphan well plugging and restoration."[49]

Activities on federal lands are regulated both by BLM regulations and by the state in which the operations are located. On federal lands, however, existing federal regulations obligate companies to bear the full costs of plugging and abandoning well sites.[50] In fact, companies cannot be released from liability until BLM determines they have properly done so. The April 2019 GAO report identified 296 orphaned wells which is a very small and manageable percentage of the 96,199 onshore federal wells.[51]

Beyond state and federal requirements, the oil and gas industry has developed relevant standards and practices which apply on both state and federal lands. These are relevant throughout a well's lifecycle; covering the safe conduct of drilling operations, standards for equipment and materials used during drilling and completion, and practices for well plugging and abandonment. In 2021, API's Recommended Practice (RP63),5- *Wellbore Plugging and Abandonment* provided specific guidance for the design, placement and verification of cement plugs used in wells that will be temporarily or permanently closed.[52] The standard also provides guidance for well remediation and verification of annular barriers, reinforcing groundwater protection and emissions retention. RP 65-3 joins several established API standards already in use for decades, including but not limited to API 51R, *Environmental Protection for Onshore Oil and Gas Production Operations and Leases* and API 65-2**,** *Isolating Potential Flow Zones During Well Construction*. These are instructive templates for better understanding how industry practices work effectively across varying state and federal regulations.

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[49] IOGCC (2021) at 3.

[50] Ref federal regs See e.g., Bureau of Land Management, Onshore Order No. 2, 53 Fed. Reg. 223 (1988), available at https://www.blm.gov/sites/blm.gov/files/energy_onshoreorder2.pdf , and other onshore orders available at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/onshore-orders

[51] Government Accountability Office, Report 19-615 Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Repair Wells (2019) p. 14, citing Footnote 30 explaining that anecdotally BLM also indicated some of these 296 wells may no longer be orphaned.

[52] API RP-63 American Petroleum Institute, Recommended Practice 65-3, *Wellbore Plugging and Abandonment* (2021).

10.1.5 The emissions from non-producing oil and gas wells are comparatively small and may currently be overestimated within the datasets used by EPA's Inventories Program on Climate Change.

It is noteworthy that, under EPA's current methodology, the emissions from non-producing oil and gas wells constitute approximately 3% of all methane emissions from the energy sector – a number similar to rice cultivation.[53]

Definitional challenges across state agencies and data sets can lead to apples-to-oranges comparisons. For example, the distinction between "abandoned" and "abandoned and plugged" is considerable. Beyond the IOGCC definitions discussed above, the oil and gas industry often refer to any well that has been properly plugged as "abandoned and plugged." Similar to industry, EPA's definition of "abandoned" includes all wells that are no longer in production; however, these wells may or may not be plugged, and may or may not be considered "orphan" as defined by IOGCC This type of information is part of an ongoing dialogue with EPA's Climate Change Division concerning potential updates to the U.S. Greenhouse Gas Inventory (GHGI).

In the attached letter (Attachment D) dated November 16, 2021, to Ms. Melissa Weitz, API recommended the following clarifications and revisions to EPA's proposed methodology,[54] all of which underscore the challenge of creating an accurate count of wells across data systems:

- **Correcting assumptions concerning plugged vs. unplugged wells.** API requests from EPA a better explanation of how it estimated the number of 1.1 million historical abandoned wells, which are not captured in the Enverus database. Moreover, API maintains that EPA should not assume that all historical (pre-Enverus) wells are unplugged, without further supporting information. Looking at the restructured Enverus data at the end of 1975, which is the date EPA used to develop its estimate of historical (pre-Enverus) wells, indicates that 72% of the wells that would be classed as 'abandoned' by the criteria in Table 3 of the 2022 memo are shown as actually 'plugged and abandoned'.[55] Hence, EPA should not ignore the Enverus data in favor of unsupported assumptions.

- **Using the IOGCC Data.** API contends that an alternative estimate of historically abandoned wells could be based on data for 'undocumented orphan wells' provided in the 2019 report issued by the Interstate Oil & Gas Compact Commission (IOGCC).[56] According to the IOGCC 2019

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[53] GHGI United States Environmental Protection Agency, Global Greenhouse Gas Inventory (2019).

[54] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-abandoned-wells_sept-2021.pdf 2 IOGCC, 2019, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies.

[55] API's analysis of Enverus data does not validate the information in Table 3 of the 2022 Abandoned Wells Update Memo as representative of calendar year 2019. However, the counts in Table 3 are broadly similar to API's analysis of current date Enverus well counts. API requests that EPA should validate that their modified query of the Enverus database for 2019 counts is correct and provide this information to stakeholders in an updated Table 3 if changes are substantive.

[56] See https://iogcc.ok.gov/sites/g/files/gmc836/f/documents/2021/2020_03_04_updated_idle_and_orphan_oil_and_gas_wells_repo rt.pdf Updates Under Consideration – 2022 GHGI

report the total estimated number of undocumented orphan wells reported by the states is between 210,000 and 746,000 (as shown in Table 1. Total Idle and Orphan Wells: All Surveyed States and Provinces (2018)). Beyond the IOGCC information, API is not aware of alternative, high quality sources of data readily available to inform the count of abandoned wells or the split into plugged and unplugged categories.

- **Avoiding the double counting of dry wells.** API also asks EPA to provide greater insight into the process of restructuring of the Enverus data set and the treatment of dry wells. API notes that the designation of “Dry Wells” in the Enverus database indicate a production type rather than a status type and EPA’s approach of considering all wells with no cumulative production as abandoned wells is likely leading to double counting of dry wells in the abandoned well category since they are embedded in the well status counts. Furthermore, EPA’s assumption that dry wells are unplugged is neither consistent with the Enverus data nor State plugging requirements. Current Enverus data shows that 93% of dry holes are plugged. Texas requires the same plugging standards for dry holes as for idle production wells and other State requirements are believed to be similar. Moving forward, API recommends that EPA should continue to use the Enverus production type field, where available, to classify wells into gas vs. oil and should also use the Enverus P&A status for determining what dry holes are unplugged. API further recommends that EPA should continue to use the cumulative production coupled with the well status and production type information to determine the count of dry wells.

In that same letter dated November 21, 2021, API also highlighted some data considerations which may lead to an overestimation of emissions from those wells:

- ***Considering the impact of state regulations.*** Many of the largest producing states have regulations in place spelling out emissions, discharge or integrity requirements that must be met when a well is non-producing. API stipulates that the simple assignment of the ‘unplugged’ designation to all the status codes that are not ‘Excluded’ or ‘Plugged and Abandoned’ (P&A) overlooks the potential impacts of such regulations and is therefore inaccurate. Such regulations, even if not directly promulgated to control volatile emissions, have the potential for lower emission rates from wells that are subject to regulation when inactive.

- ***Using geographically correct emissions factors.*** API commented previously on Abandoned Wells emissions when EPA introduced the update for the 2018 GHGI. API noted that the studies conducted so far have limited geographical coverage and may not be nationally representative. To clarify, EPA uses the “entire U.S.” emission factors from the Townsend-Small study, which include the much higher Eastern U.S. (Appalachian - Ohio) emission factors. They then use these same Eastern US factors from Townsend-Small coupled with emissions from Kang 2016 to develop emission factors for Appalachian basin abandoned wells. API recommends that EPA should use the more appropriate “western U.S.” emission factors for abandoned wells outside of the Appalachian basin.

- ***Treating outliers appropriately.*** Additionally, the Townsend-Small Appalachia data are dominated by one well with emissions of 146 grams/hour that is about an order of magnitude higher than any other well, plugged or unplugged, in the Townsend-Small data. API contends that it is not appropriate to include this well in the emission factor for the entire US. Also, to date no emissions data are available from the state of Texas or many other major producing areas, calling into question the representativeness of the extrapolation of the results of the current studies to a nationwide estimate of the contribution of CH4 emissions from Abandoned Wells to the GHGI.

Similarly, it is important to note that other parts of the U.S. government are already considering the question of outliers or super-emitters. During a recent presentation to the Health Effects Institute, Natalie Pekney from the Department of Energy's National Energy Technology Lab (NETL) presented research showing that a comparatively small number of super-emitter wells are increasing the average emission rate.[57] This estimate was based on NETL's techniques for locating undocumented orphan wells by searching for magnetic signatures (using walking, helicopters, and drones) which have been validated through field work in Pennsylvania, Oklahoma, and Kentucky. EPA may benefit from looking at NETL's work in more detail, particularly since NETL intends to undertake more work in this area in Kentucky, New York, and Texas over the next few years.[58] This observation would be consistent with the states' established practice of prioritizing plugging and abandonment for individual wells; consequently, EPA may benefit from learning more about both NETL's research and considering how it may already be applied at the individual state level.

10.2 Pipeline "Pigging" Operations

As mentioned by EPA, there are several alternatives for reducing the various emissions from pigging operations. As each location has a different set of circumstances for its operations, the focus should be on reducing emissions volumes associated with pigging operations, allowing facilities to implement the necessary emission reduction alternatives that are most appropriate.

Some alternatives might be appropriate for broad application and other alternatives could require unreasonable cost and infrastructure modification for minimal emissions reductions. Existing programs and practices already implemented by operators also need to be considered. There is a distinction in the feasibility of capturing and controlling pigging emissions from those pig launchers and receivers co-located at a compressor station or gas plant as compared to remote launcher and receiver locations where supporting infrastructure (i.e., electrical power, line jumpers to low pressure pipelines, flares, etc.) does not exist.

The discussion below provides an example of how emissions from a pig launcher or receiver can vary widely.

Emissions from a pig launcher or pig receiver occur primarily from opening the isolated pig barrel (and often a short distance of piping connected to the pig barrel) to either insert or remove a pig. The emissions are from the natural gas inside this isolated area when the pig barrel is opened, which is

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[57] Slide 8.Dr. Natalie Pekney, presentation on Health Effects Institute's webinar concerning "Abandoned and Orphaned Oil and Gas Wells," November 30, 2021.
[58] *Id.*

typically called a “blowdown.” When a pig receiver is opened, there may be some residual liquids in the receiver, primarily from liquid falling off the pig itself. We note the volume of liquids in the receiver is unrelated to the amount of liquid a pig pushes down a pipeline. This limited amount of liquid in the receiver may have the potential for minimal flash emissions and perhaps volatilization.

Emissions from pig launchers and receivers vary widely based on several different, and sometimes interrelated factors: the diameter of the pig barrel and connecting midstream gathering pipeline; the length of the barrel or portion of the midstream gathering pipeline in between the pigging unit isolation valves; the pressure and composition of the gas within the unit; pig launching or receiving frequency; and the amount of liquids accumulation (applicable to receivers only). Consequently, frequency of pigging operations alone is not a good proxy for actual emissions as it is just one element that informs emissions. As a result, if one were to compare two pig launchers that are each used once per month, where the temperature is the same and the gas composition is the same, but the barrels have different diameters and lengths and different pressures, the actual emissions—calculated using the ideal gas law—from the two launchers would not be equal, potentially by a wide margin.

10.3 Tank Truck Loading Operations

Options typically used to reduce emissions from truck loading include routing emissions to a process (e.g., by installing a vapor recovery unit (VRU)) or to a combustion device. Many operators use a single, common VRU system or combustion device to control emissions from both hydrocarbon liquid transfers and storage tanks.

Practical, technical and safety issues that EPA should consider when evaluating potential truck loading emissions controls include the following:

- When loading emissions are to be routed to an existing combustion control device, substantial design evaluation work may be required to ensure that use of existing control devices is feasible, and if not, to design and install an additional or larger capacity combustion device.
- Some older facilities do not have the pad size to safely locate an additional combustor dedicated to loadout controls (if needed). Changes to the pad size require state agency and landowner approval, which may not be obtainable. Additionally, local governments and landowners may further prohibit operators expanding the footprint of a facility.
- If truck loadout vapors are routed through the storage tanks onsite prior to combustion, a new design analysis may be needed, which may generate costly modifications to low-producing sites (e.g., adding additional combustion control, larger combustors, change pipe sizing, etc.) in order to properly design the facility.
- Loadout truck drivers, who may not be familiar with truck loadout air emission equipment being used at these older low production facilities, will need additional training to safely use the new equipment. In many situations, the trucking company is a separate entity that may change over time from the producer.

- Older vintage buried and semi-buried tanks are not designed to work with truck loadout equipment.
- There are potential safety issues with the introduction of an oxygen rich vapor stream into atmospheric tanks that have minimal headspace. A higher oxygen percentage in the vapor mixture increases the risk of the vapor igniting and causing a fire or explosion. In these cases, the installation of an independent vapor control system may be required.
- Loading controls should not be required for sites where tanks are not required to be controlled.
- Lower producing facilities may have infrequent truck loadings based on production decline. EPA must evaluate the cost effectiveness of a reasonable threshold of crude oil/condensate prior to requiring any controls. Some states do not require loading controls if the number of loadouts is below a certain threshold or if the site routinely transfers liquids via a pipeline.

10.4 Opportunities to improve performance and minimize malfunctions on flares

EPA is soliciting comment on potentially proposing a change in the standards for wet seal centrifugal compressors, storage vessels, and pneumatic pumps that would require 98 percent reduction of methane and VOC emissions from these affected facilities. API does not support this change.

EPA also seeks comment on the appropriateness of applying standards from The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, amended in 2015 (80 FR 75178) to the oil and gas production, gathering and boosting, gas processing, or transmission and storage segments.

> *"The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, were amended in 2015 (80 FR 75178) to include a series of additional monitoring requirements that ensure flares achieve the required 98 percent control of organic compounds. Previously these flares had been subject to the flare requirements at 40 CFR 60.18 in the part 60 General Provisions. More recently, the updated flare requirements in NESHAP subpart CC have been applied to other source categories in the petrochemical industry, such as ethylene production facilities (40 CFR part 63, subpart YY), to ensure that flares in that source category also achieve the required 98 percent control of organic compounds. These monitoring requirements include continuous monitoring of waste gas flow, composition and/or net heating value of the vent gases being combusted in the flare, assist gas flow, and supplemental gas flow. The data from these monitored parameters are used to ensure the net heat value in the combustion zone is sufficient to achieve good combustion. The monitoring also includes prescriptive requirements for monitoring pilot flames, visible emissions, and maximum permitted velocity. Lastly, where fairly uniform, consistent waste gas compositions are sent to a flare, owners or operators can simplify the monitoring by taking grab samples in lieu of continuously monitoring waste gas composition, and in some instances, engineering calculations can be used to determine flow measurements."*

As we have provided feedback in the past[59], the refining sector is vastly different than oil and gas well sites, centralized production facilities, and compressor stations. The oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Oil and natural gas are located thousands of feet below the surface and must flow in two or three phases to the surface. The mixture is then separated in the two or three phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system.

As production declines in a gas well, management of wellbore liquids can mean that flow to the control device can vary from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible in these conditions.

Applying refinery-oriented requirements to upstream flares is not appropriate nor cost effective. Costs for Subpart CC controls at refineries are $1 million plus, with major ongoing costs. Costs would be much greater at upstream facilities without the necessary utilities and instrumentation resources. Nor is it clear that there is instrumentation available that would work reliably under the varying operating conditions. Additionally, adding natural gas to a flare to control the BTU content incurs capital costs as well as ongoing costs, and generates considerable greenhouse gases that would not otherwise be emitted.

We note that many states have moved to include some type of flare monitoring requirement within their local regulations or permitting processes. For example, Texas[60] requires that flares meet 40 CFR 60.18 requirements for minimum heating value and maximum tip velocity and have a continuous pilot flame (monitored by thermocouple or equivalent device) or an automatic ignition system.

10.5 EPA should clarify its statements regarding the Crude Oil and Natural Gas source category and the extent of crude oil operations for purposes of this rulemaking.

In footnote 2 of the proposal's Executive Summary section I.A. (86 FR 63113), EPA states:

> *"The EPA defines the Crude Oil and Natural Gas source category to mean (1) crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.* ***For purposes of this proposed rulemaking, for crude oil, the EPA's focus is on operations from the***

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[59] API's December 4, 2015, comments on the proposed Subpart OOOOa

[60] Texas Commission on Environmental Quality, *Control Device Requirements Charts for Oil and Gas Handling and Production Facilities* (February 2012). https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/control-dev-reqch.pdf

> ***well to the point of custody transfer at a petroleum refinery** [emphasis added], while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.*

Similarly, in the text in section III.B. (86 FR 63128), EPA states:

> *"The EPA regulates oil refineries as a separate source category; accordingly, as with the previous oil and gas NSPS rulemakings, **for purposes of this proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery** [emphasis added], while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate.''*

The implications of EPA's statements are unclear. We do not believe that EPA intends to regulate crude oil operations beyond the point of custody transfer from a well to a transmission pipeline (for example, operations at a crude oil pipeline breakout terminal). We request that EPA clarify these statements in the supplemental proposal.

10.6 Use of the Social Cost of Methane in the EPA Regulatory Impact Analysis

10.6.1 API recognizes the importance of including the potential impacts of climate change in regulatory impact analyses.

When performing a benefit-cost analysis as part of a RIA, EPA is justified in applying an estimate of the value of the impacts of a regulation to reduce greenhouse gases. This is especially true in a regulation which has as its primary purpose the reduction of greenhouse gases. As noted in OMB Circular A-4, the monetization of as many impacts as possible, and especially those central to the regulation, is essential to a properly conduced benefit-cost analysis.[61] However, specific care must be taken when using the social cost of methane estimates (SC-CH_4) as an input to the RIA. Per the recommendations of the National Academies of Science, Engineering and Medicine (NASEM) in their 2017 review of the social cost of carbon estimates (SCC),[62] the social cost estimates should be presented with a full discussion of the uncertainties associated with the development and presentation of those estimates. This RIA describes some of the uncertainties well and includes a presentation of the frequency distributions used to generate the social cost estimates. However, there are some issues that have not been addressed, including the inability to use a consistent set of socioeconomic and emissions scenarios to generate both

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[61] Office of Management and Budget, *Circular A-4* (September 17, 2003). https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf

[62] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. Washington, DC: The National Academies Press. https://doi.org/10.17226/24651

the social cost estimates and other benefits and costs associated with the regulation, and a consistent application of discount rates.

10.6.2 The interim social cost of methane estimates present a flawed approach to monetizing the impacts of climate change.

As noted in the 2021 Technical Supporting Document (2021 TSD), the interim social cost estimates represent the same methodological approach as the estimates generated prior to the disbanding of the Interagency Working Group (IWG) in 2017, and therefore rely on the same models and inputs from that effort.[63] API has previously commented on the social cost of greenhouse gas estimates (SC-GHG), including the SCC and the SC-CH_4 as developed by the IWG before 2017.[64] In these prior comment opportunities, API raised issues relating to the use of discounting, averaging across scenarios and Integrated Assessment Models (IAMs), the socio-economic and emission scenarios on which the modeling is built, and the handling of methane by the three IAMs on which the estimates rely. The conclusion upon reviewing these shortcomings of the previous and current interim SC-CH_4 estimates was "The SC-CH_4 (and SCC) estimates are highly uncertain and the causes of the uncertainty are not well understood."[65] While the NASEM study provided a better understanding of the uncertainties associated with the SCC and opportunities to improve the methodology of the SCC, the study did not extend to the SC-CH_4 nor did the IWG seek to improve the calculation of the SC-CH_4 in the publication of the interim values of 2021, as noted above.

10.6.3 Updates to the social cost estimates should be considered with robust stakeholder engagement.

The 2021 TSD notes that many of the same issues raised by API above are inputs that "need to be updated."[66] API and its members agree with this assessment; however, we have been concerned by the approach currently being taken by the IWG. As noted in API's comments to OMB regarding the Interim social cost estimates in June 2021, the actions taken thus far by the IWG do not reflect this administration's commitment to "public participation and an open exchange of ideas."[67] To date, there has been only one opportunity for stakeholder engagement in the social cost estimate development process initiated by E.O. 13990 – one that amounted to a request for information not an opportunity to comment on the work undertaken by the IWG. A recent brief filed by the Department of Justice suggests

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[63] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990* (February 2021), page 5. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[64] *See* multi-association comments filed February 26, 2014 (OMB-2013-0007-0140); API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776); and, API comments filed June 21, 2021 (OMB-2021-0006).

[65] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776).

[66] Interagency Working Group, 2021 TSD at 4.

[67] Executive Order 13563, *Improving Regulation and Regulatory Review* (January 28, 2011), at Sec. 1(a). https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/inforeg/inforeg/eo12866/eo13563_01182011.pdf

that stakeholders will have an opportunity to comment on the revised social cost estimates that the IWG will propose in spring of 2022. In its brief, the DOJ stated that the IWG will "publish its proposed final estimates within the next two months," and that the public will be given the opportunity to comment on these proposed estimates.[68] Further, EPA has published a request for nominations to form a panel to provide an independent, scientific peer-review of the forthcoming estimates.[69] The indication of both an independent, expert peer-review and a public notice and comment period is a welcome development. API encourages the IWG to use the forthcoming opportunities to engage with stakeholders, address comments that are provided and seek further feedback. Along these lines, we encourage EPA to submit for public comment a list of questions EPA is considering to guide the expert peer-review along with the list of candidates as outlined in the EPA request for nominations.[70] These forthcoming engagements represent an opportunity for the IWG and EPA to improve their process.

Separately, the DOJ brief also indicated that the IWG has not yet submitted recommendations for the use of the social cost estimates across federal decision-making. API encourages the IWG and the White House to publish those recommendations, in full, for public comment.

API and its members look forward to the opportunities noted above to engage with the IWG and relevant agencies on the development and application of the social cost estimates. The provision of a well-developed estimate of the impacts of greenhouse gas emissions is key to regulations that seek to address such emissions. Failure to engage with stakeholders directly during the process or during a public comment period specifically to address the methodology of the estimates may jeopardize the durability of regulations dependent on this analysis. API encourages EPA, as a member of the IWG, to direct the IWG to follow through on the administration's commitment to public participation by opening the process and engaging directly with stakeholders.

Given the timeline set by this administration, and the updated timeline for the proposal of revised social cost estimates, it is likely that the IWG will have proposed a revised set of social cost estimates for stakeholder review and comment prior to EPA issuing a supplemental proposal or a final rulemaking for methane emissions from the oil and natural gas sector. API encourages EPA to complete a revised RIA including these new estimates and other factors as necessary before moving forward.

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[68] Def. Supp. Br., 23, *La. v. Biden*, No. 2:21-cv-01074 (W.D. La. Jan. 21, 2022).

[69] On Tuesday, January 25th, EPA published a request for nominations of experts to act as reviewers of the proposed final estimates and the accompanying Technical Supporting Document (TSD). 87 Fed. Reg. 3801 (January 25, 2022)

[70] 87 Fed. Reg. 3803 (January 25, 2022)

11.0 OVERARCHING LEGAL ISSUES

11.1 The Proposal cannot set the new source trigger date under Subpart OOOOb because regulatory text is missing.

EPA proposes that the new source trigger date for Subpart OOOOb is November 15, 2021, the date the Proposal was published in the Federal Register. But here, publication of the Proposal cannot set the new source trigger date because the Proposal lacks proposed regulatory text, which is vital for fully assessing applicability and compliance. We appreciate EPA's promise to make proposed regulatory text available in an upcoming supplemental proposal. But that promise is not sufficient to set the new source trigger date at November 15, 2021.

Lack of proposed regulatory text creates an insurmountable practical problem. Affected facilities cannot know with certainty what regulatory requirements EPA has proposed and are thus unable to reasonably plan to comply with the final rule. Affected facilities can only surmise what the rule would require based on the description and explanation provided in the preamble. But affected facilities cannot know with sufficient clarity what would be required under the Proposal because they cannot see the part of the proposal that matters most – the regulatory text that would establish the binding legal obligations that would be imposed under the proposal.

As an initial matter, the lack of regulatory text means that the Proposal does not give fair notice to potentially affected facilities of what requirements they might be required to meet upon the effective date of the final rule. Fair notice is only achieved when EPA provides regulated entities with sufficient detail of what exactly will be required, which it has not done here.

Moreover, the publication date of the Proposal does not set the trigger date because it is not a proposed "regulation." CAA § 111(a)(2) defines "new source" to mean "any stationary source, the construction or modification of which is commenced after the publication of regulations (***or, if earlier, proposed regulations***) prescribing a standard of performance under this section which will be applicable to such source." CAA § 111(a)(2) (emphasis added). Thus, only a proposed "regulation" may set the new source trigger date.

The term "regulation" is not defined in the Clean Air Act. However, the term "regulation" is synonymous with the term "rule," which is defined in the Administrative Procedure Act to mean (in relevant part) "the whole or a part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or describing the organization, procedure, or practice requirements of an agency." 5 U.S.C. § 551(4).

Here, the preamble alone cannot constitute a proposed rule any more than a final rule that is unaccompanied by regulatory text could be declared a "rule." Although the current preamble describes the type of regulatory requirements that EPA proposes to eventually promulgate, the preamble is not in and of itself a document that establishes the "agency statement of general or particular applicability and future effect." That type of required statement would be established only by the proposed regulatory text, which is absent here.

Thus, the Proposal cannot establish the new source trigger date because it does not include a proposed rule. The new source trigger date is tied to the date proposed regulatory text is published in the Federal Register.

As a last note, the CAA § 307(d) administrative rulemaking procedures do not expressly require a proposed rule to include proposed rule text. We do not opine on the question of whether a proposed rule subject to CAA § 307(d) provides adequate public notice and an opportunity to comment if it does not include or make available proposed rule text. But that issue is beside the point here because the new source trigger date is defined in CAA § 111(a)(2) and not in CAA § 307(d). So, even if the current proposal satisfies the procedural requirements of CAA § 307(d), it does not set the new source trigger date for the reasons explained above.

11.2 The CRA rescission of the 2020 Policy Rule does not extend to the legal rationale and policy positions used to justify the 2020 Policy Rule and does not endorse the legal and policy interpretations in the preceding 2012 and 2016 rules.

EPA explains that, as one of the three primary elements of the Proposal, it "is taking several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021 under the Congressional Review Act (CRA), disapproving the EPA's final rule titled, 'Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,' 85 FR 57018 (Sept. 14, 2020) ("2020 Policy Rule")." 86 Fed. Reg. at 63110. EPA further explains that:

> Under the CRA, the disapproved 2020 Policy Rule is "treated as though [it] had never taken effect." 5 U.S.C. 801(f). As a result, the preceding regulation, the 2016 NSPS OOOOa Rule, was automatically reinstated, and treated as though it had never been revised by the 2020 Policy Rule. Moreover, the CRA bars EPA from promulgating "a new rule that is substantially the same as" a disapproved rule. 5 U.S.C. 801(b)(2), for example, a rule that deregulates methane emissions from the production and processing sectors or deregulates the transmission and storage sector entirely.

Id. at 63151.

EPA further asserts that, in the legislative history of this CRA action, Congress "rejected the EPA's statutory interpretations of section 111 in the 2020 Policy Rule and endorsed the legal interpretations contained in the 2016 NSPS OOOOa Rule." *Id*. In other words, EPA asserts that the CRA action rescinded not just the 2020 Policy Rule, but also the "statutory interpretations" that stood behind the 2020 Policy Rule. EPA is incorrect.

The CRA applies to "rules." Most importantly, the CRA provides that "[a] ***rule*** shall not take effect (or continue), if the Congress enacts a joint resolution of disapproval" pursuant to CRA § 802. 5 U.S.C. § 801(b)(1) (emphasis added). Similarly, "[a] ***rule*** that does not take effect (or does not continue) … may not be reissued in substantially the same form." *Id*. at § 801(b)(2) (emphasis added). As explained above, the term "rule" is defined to mean "the whole or a part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or describing the organization, procedure, or practice requirements of an agency." 5 U.S.C. § 551(4). When EPA promulgates a final rule, the "rule" is the regulatory text (which imposes legal obligations or creates legal rights) and not the explanation and justification provided in the preamble to the rule. *See also* The Congressional Review Act (CRA): Frequently Asked Questions. Congressional Research Service (Nov. 12, 2021) at 18 (available at https://crsreports.congress.gov/product/pdf/R/R43992).

Thus, a rescission under CRA § 801(b)(1) and the prohibition under CRA § 801(b)(2) on issuing a rule in substantially the same form apply only to the relevant regulatory text and do not apply to EPA's explanation in the administrative record that accompanies the regulatory text. Contrary to EPA's suggestion, the legislative history of this particular CRA action cannot and does not change the plain meaning of the CRA statute. *See INS v. Cardoza-Fonseca*, 480 U.S. 421, 452-3 (1987) (J. Scalia, concurring in the judgment) ("Judges interpret laws rather than reconstruct legislators' intentions. Where the language of those laws is clear, we are not free to replace it with an unenacted legislative intent.").

As a final note, EPA's suggested approach would indiscriminately and inappropriately sweep away legal and policy positions stated in the record of the Policy Rule that are necessary for proper implementation of CAA § 111. For example, EPA explains in the preamble to the final Policy Rule that VOC "are not the type of air pollutant that, if subjected to a standard of performance for new sources, would trigger the application of CAA section 111(d)." 85 Fed. Reg. at 57040. Reversal of this uncontroversial interpretation would cause CAA § 111(d) to have a far broader scope than is reasonable or warranted under the plain text of the statute. Such an outcome is not required or supported by the CRA action.

11.3 API supports EPA's effort to improve and expand the methane emissions control program, however, the cost effectiveness threshold for methane used in the Proposal is not adequately justified.

EPA asserts flexibility as to how cost may be considered in determining BSER in the Proposal. 86 Fed. Reg. at 63154. But the Agency primarily relies on cost effectiveness thresholds expressed in dollars per ton of pollutant reduction. For methane, "EPA finds the cost-effectiveness threshold values up to $1,800/ton of methane reduction to be reasonable for controls that [it has] identified as BSER in this proposal." *Id*. at 63155.

EPA explains that "[u]nlike VOC, [it] does not have a long regulatory history to draw upon in assessing the cost effectiveness of controlling methane, as the 2016 NSPS OOOOa was the first national standard for reducing methane emissions." *Id*. In that 2016 rule, EPA "determined that methane cost-effectiveness values for the controls identified as BSER … range up to $2,185/ton of methane reduction." *Id*. "[B]ecause the cost-effectiveness estimates for the proposed standards in [the Proposal] are comparable to the cost-effectiveness values estimated for the controls that served as the basis (i.e., BSER) for the standards in the 2016 NSPS OOOOa, [EPA] consider[s] the proposed standards to also be cost effective and reasonable." *Id*.

Thus, the only justification the EPA presents for using a methane cost effectiveness threshold of $1,800/ton is that the Agency used a similar methane cost effectiveness threshold in the 2016 NSPS OOOOa rule. That "because we did it before" justification is wholly inadequate in API's view.

CAA § 111 requires that EPA develop a record to support its determination that the NSPS standards "represent[] the best balance of economic, environmental, and energy considerations." *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981). And an agency action is arbitrary and capricious if it does not "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983) (internal punctuation and citations omitted). Here, EPA fails to meet these standards because it presents essentially no "relevant data" to support its proposed cost effectiveness threshold and, because of that, cannot and does not explain how the "relevant data" inform the choice of $1,800/ton.

For example, perhaps EPA believes that using values up to $2,185/ton in the 2016 rule provides evidence that values in this range are acceptable in the current proposal because the 2016 rule has been widely implemented across the affected industry. If this is what EPA believes, it should have said so. But it didn't.

Moreover, EPA has made no effort in the current rule to show why $2,185/ton is an appropriate touch stone, beyond simply asserting it to be true. That failure to present "relevant data" and to explain how those data inform the current proposal fundamentally undermines the proposed value of $1,800/ton. This is particularly important because, even under the Clean Air Act, two "wrongs" do not make a "right." *See New Jersey v. EPA*, 517 F. 3d 574, 583 ("[P]revious statutory violations cannot excuse the one now before the court.").

Lastly, EPA's factual determinations must be "supported by substantial evidence when considered on the record as a whole." *Coalition for Responsible Regulation v. EPA*, 684 F. 3d 102, 122 (D.C. Cir. 2012). The $1,800/ton threshold is supported by no evidence at all, much less substantial evidence.

11.4 API supports appropriate consideration and adequate protection of disadvantaged groups; however, EPA has not adequately explained how the proposed mandatory procedural requirements designed to foster "meaningful engagement" are authorized under the CAA.

EPA has made Environmental Justice a priority in developing the Proposal. For example, EPA made extensive outreach to disadvantaged and potentially overburdened populations and proactively sought to address their concerns in the proposal. EPA also included provisions in the Proposal that are at least partially designed to address Environmental Justice issues. For example, EPA explains that it provided for the use of "cutting edge" technologies in the rule, "alongside a rigorous fugitive emissions monitoring program that is based on traditional OGI technology." 86 Fed. Reg. at 63139. To address the concern of "addressing large emission sources faster," EPA proposes "more frequent monitoring at sites with more emissions." *Id*. And in response to concerns about health impacts, "EPA is proposing rigorous guidelines for pollution sources at existing facilities, methane standards for storage vessels, strengthened and expanded standards for pneumatic controllers, and standards for liquids unloading events that will further reduce emissions." *Id*.

API supports EPA's attention to potential Environmental Justice issues and agrees that the measures described above will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The natural gas and oil industry's top priorities are protecting the public health and safety – regardless of race, color, national origin or income – and the environment. We strive to understand, discuss and appropriately address community concerns with our operations. We are committed to supporting constructive interactions between industry, regulators, and surrounding communities/populations that may be disproportionately impacted.

While API supports EPA's goals, the Agency has not provided sufficient detail in the proposal to allow API to comment in a meaningful way. There is no proposed language to understand the impact of what the Agency intends to do, and other than broad statements that the requirements are authorized under CAA Sections 111(d) and 301(a)(2), no explanation of the substantive legal underpinnings of this concept. We look forward to the opportunity to offer further thoughts on this important topic in comments on the upcoming supplemental proposal.

11.5 Empowering local citizens by providing better access to relevant monitoring data is a worthy goal; however, EPA has not explained the legal basis for establishing a "community monitoring" program as described in the Proposal.

EPA presents a preliminary concept that would "take advantage of the opportunities presented by the increasing use of [advanced methane detection systems] to help identify and remediate large emission events (commonly known as "super-emitters")." 86 Fed. Reg. at 63177. "Specifically, the EPA seeks comment on how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event." *Id*.

API concurs with the importance of identifying and addressing large emissions events. Emissions from such events can be much greater than those from normal operations at a given facility and can result in material economic losses. API's overall support for the Proposal is grounded in a shared interest in seeking to reduce the incidence of such large emissions events.

Having said that, the community monitoring concept presented in the Proposal is novel. To our knowledge, it would be the first time under the CAA that EPA asserts authority to create regulatory obligations for affected facilities based on monitoring conducted by unaffiliated third parties. In concept, this provision would be akin to an LDAR program where an unaffiliated third party does the monitoring and the affected facility then has the legal obligation to address leaks identified by that monitoring. That is a truly new approach under CAA § 111 and the CAA as a whole.

Unfortunately, in describing the concept, EPA does not explain the legal basis for establishing such a provision. That, of course, is essential to understanding whether such a novel provision is legally viable.

We are concerned that EPA does not appear to have such authority. To begin, CAA § 111 calls for standards of performance to be established for emissions sources in regulated source categories. The statute unambiguously specifies that the Administrator shall establish standards of performance for new sources and the states should do so for existing sources. CAA §§ 111(b)(1)(B) and (d)(1). This scheme does not appear to leave room for regulatory obligations to be defined by the actions of third parties.

Moreover, EPA's authority to establish monitoring requirements is limited under CAA § 114 to just four entities: (1) any person who owns or operates any emissions source; (2) certain entities that manufacture emissions control or process equipment; (3) those with information "necessary for the purposes" of CAA § 114; and (4) those "subject to the requirements of this Act." CAA § 114(a)(1). The third parties EPA describes in the Proposal do not appear to fall into any of these four categories.

We note that CAA § 304 expressly prescribes a role for citizens in CAA implementation by authorizing them to file civil lawsuits challenging alleged violations of, among other things, CAA § 111 emissions standards. Congress did not provide similar express language in CAA § 111 or elsewhere in the CAA authorizing the sort of citizen monitoring described in the Proposal. In this context, the absence of such language likely would be construed as a limitation on EPA's authority to allow such monitoring and would not be seen as an implicit delegation of authority from Congress to EPA.

If the Agency decides to actually propose a community monitoring provision in the forthcoming supplemental proposal, we encourage EPA to carefully consider these issues and clearly explain the purported legal basis for any such provision. In addition, EPA must clearly describe important details, such as how the Agency will quality assure third-party monitoring, what monitoring levels are actionable, and the mechanism by which monitoring data are determined to be actionable (*e.g.*, must affected facilities act on data submitted directly to them by third parties, or will EPA or a state regulatory agency determine when the need for action by affected facilities is triggered). And, of course, corresponding proposed regulatory text must be provided.

Lastly, these are complex issues that would benefit from further discussions between EPA, affected facilities, and other interested parties. We encourage EPA to conduct additional outreach on this issue prior to crafting the supplemental proposal. API would welcome the opportunity for a meeting.

11.6 Three proposed "modification" definitions are unlawful because they cover activities that are not a physical change or change in the method of operation of an affected facility that results in an emissions increase.

EPA proposes three equipment or activity-specific modification definitions that encompass actions that are not actually modifications. These must not be included in the final rule.

First, EPA proposes for centralized production facilities ("CPF") that a modification includes (among other things) when "a well sending production to an existing centralized production facility is modified." 86 Fed. Reg. at 63173. Second, EPA proposes that a single storage vessel or a tank battery is modified when (among other things) it "receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from activities such as refracturing a well or adding a new well that sends these liquids to the tank battery)." *Id*. at 63178.

The word “modification” is defined in CAA § 111 to mean “any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.” CAA § 111(a)(3). Under this definition, two conditions must be satisfied for a modification to occur at a stationary source: (1) there must be a physical or operational change to the source; and (2) that change must result in an emissions increase or the emissions of a new pollutant.

The definitions described above share two flaws. First, a physical change or change in the method of operation is deemed to occur at a given CPF or tank/tank battery, even though no physical or operational change has occurred at that CPF or tank/tank battery. Under these definitions, the relevant physical or operational change occurs at a <u>different</u> affected facility. This plainly does not satisfy the statutory requirement that the modification of a given affected facility must entail a physical change or change in the method of operation at that same facility.

The second flaw with regard to these two definitions is that EPA has not demonstrated that these activities necessarily result in an emissions increase at the given CPF or tank/tank battery. For example, the fact that an upstream well is modified does not necessarily mean that a downstream CPF or tank/tank battery would have an actual emissions increase. More importantly, there is even less likelihood that the downstream operations would have a <u>regulatory</u> emissions increase, given that the Part 60 definition of “modification” requires an increase in the short-term potential to emit of an affected facility. 40 C.F.R. § 60.14(b).

Thus, the modification definitions for CPFs and tank/tank batteries are not consistent with the Act because: (1) they do not require a physical or operational change at the given affected facility; and (2) they presume an emissions increase where such an increase often would not occur.

A third proposed modification definition also is flawed, but for somewhat different reasons. For liquids unloading, EPA proposes that, because “each unloading event constitutes a physical or operational change to the well that has the potential to increase emissions, the EPA is proposing to determine each event of liquids unloading constitutes a modification that makes a well an affected facility subject to the NSPS.” 86 Fed. Reg. at 63210. Here, the legal problem is that liquids unloading is necessary at many wells in order to achieve the production potential of the given resource. As such, liquids unloading is part of normal operations for the well and does not constitute a physical or operational change to that well. Moreover, because the regulatory definition of “modification” measures an emissions increase in terms of the short-term potential to emit of the affected facility, it cannot be said that liquids unloading results in an emissions increase.

API acknowledges that the D.C. Circuit has held that the definition of “modification” should be construed expansively. *New York v. EPA*, 443 F. 3d 880, 886-7 (D.C. Cir. 2006). But at the same time, the court recognized that even though the term “modification” is broad, it “cannot bring an activity that is never considered a ‘physical change’ in the ordinary usage within the ambit of NSR.” *Id*. That is the case with liquids unloading.

11.7 EPA may not lawfully determine BSER to include technical infeasibility exceptions because BSER must be technically feasible.

EPA proposes two emissions standards that allow for "technical feasibility" exceptions. EPA proposes "a standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions." 86 Fed. Reg. at 63179. But "[i]n the event that it is technically infeasible or not safe to perform liquids unloading with zero emissions, the EPA is proposing to require that an owner or operator establish and follow BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible." *Id*.

EPA explains that "[a]n 'adequately demonstrated' system needs not be one that can achieve the standard 'at all times and under all circumstances.' Essex Chem., 486 F.2d at 433." *Id*. at 63213. "That said … the EPA recognizes that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible." *Id*.

Similarly, EPA is "proposing a standard under NSPS OOOOb that requires owners or operators of oil wells to route associated gas to a sales line." *Id*. at 63183. "In the event that access to a sales line is not available, [EPA is] proposing that the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions." *Id*. The same standard is proposed for existing sources under Subpart OOOOc. *Id*.

These standards are based on determinations that non-emitting techniques constitute BSER for these sources. At the same time, EPA acknowledges that non-emitting techniques are not always feasible or safe. Alternative standards are provided to cover those situations.

API supports this approach as a practical matter. We agree that non-emitting measures and methods should be used where they are technically feasible and cost effective. But EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. The proposed alternative measures are a common-sense solution.

Having said that, we are concerned that EPA has not asserted an adequate legal basis for taking this approach. In short, the fact that EPA needed to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA § 111.

A "standard of performance" must reflect the degree of emissions limitation "achievable" through application of the best system of emissions reduction that EPA finds to be "adequately demonstrated." CAA § 111(a)(1). The proposed non-emitting standards do not meet this requirement for two reasons.

First, EPA has not demonstrated that techniques that eliminate emissions from liquids unloading events are "demonstrated in practice" for purposes of designating such techniques as BSER. It is true that non-emitting liquids unloading techniques can be used in some circumstances and that associated gas can be routed to a sales line in some situations. But the need to create exceptions under both standards shows that non-emitting techniques are not demonstrated in practice for the full range of regulated activities and circumstances. In effect, EPA seeks to avoid the obligation to show that non-emitting techniques are demonstrated in practice by creating exceptions for situations where non-emitting techniques are not demonstrated in practice.

Second, the proposed non-emitting standards of performance are legally questionable because they are not "achievable," as demonstrated by the need to establish exceptions to make the standard sufficiently practicable. But this bifurcated approach falls short because EPA puts the burden on affected facilities to prove to EPA that they qualify for the exceptions. In other words, the non-emitting standards are presumptively applicable. This approach incorrectly relieves EPA of the burden of promulgating achievable standards in the first instance and improperly defers infeasibility determinations to the time when the rule is implemented and enforced rather than when the rule is promulgated.

Essex Chemical does not support the Agency's approach here. As explained above, EPA points to *Essex Chemical* for the proposition that "[a]n 'adequately demonstrated' system needs not be one that can achieve the standard "at all times and under all circumstances." 86 Fed. Reg. at 63213. But the court was saying something much different than that. The following is a fuller excerpt from the opinion:

> It is the system which must be adequately demonstrated and the standard which must be achievable. This does not require that a sulfuric acid plant be currently in operation which can ***at all times and under all circumstances*** meet the standards; nor, however, does it allow the EPA to set the standards solely on the basis of its subjective understanding of the problem or "crystal ball inquiry."

Essex Chemical Corp. v. Ruckelshaus, 486 F. 2d 427, 433 (D.C. Cir. 1973) (emphasis added). The highlighted portion of this excerpt is what EPA cites. But, in context, it is clear that the court was not saying that BSER may be determined to be "adequately demonstrated" even though the corresponding standard of performance cannot be met "at all times and under all circumstances" by facilities that might become subject to that rule. Instead, the court was saying that EPA does not need to show that a "currently" existing facility (*i.e.*, one in existence when EPA is formulating the rule) can meet the new standard of performance "at all times and under all circumstances."

In other words, the court confirmed that, given adequate justification, EPA may set technology-forcing standards of performance under CAA § 111 – standards that existing facilities would not necessarily be able to meet. This does not support EPA's proposal here to determine that non-emitting techniques are "adequately demonstrated" when it is clear that some significant number of potentially affected facilities will not be able to meet the non-emitting standards.

In sum, CAA § 111 requires BSER to be "adequately demonstrated" and standards of performance to be "achievable." We urge EPA in the upcoming supplemental proposal to provide a better explanation of how setting presumptively applicable non-emitting standards with a case-by-case "off ramp" satisfies these statutory requirements.

11.8 EPA should not define and impose practical enforceability requirements without first developing a coherent approach for all EPA programs.

EPA proposes "to include a definition for a 'legally and practicably enforceable limit' as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules." 86 Fed. Reg. at 63201. "The intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy." *Id*.

API believes that improving the clarity of the storage vessel applicability criteria is a worthwhile effort. However, the question of what constitutes an acceptable and effective "legally and practicably enforceable limit" goes well beyond the four corners of this regulation and has implications far beyond this narrow regulatory provision. This question is relevant across EPA's Clean Air Act stationary source programs: from major source permitting under NSR/PSD, to the Title V operating permit program, to all manner of federal and state emissions control programs (of which CAA § 111 is just one).

And, what constitutes an acceptable and effective "legally and practicably enforceable limit" has been an open question since the mid-1990s, when the prior "federal enforceability" requirement was remanded or vacated across EPA's programs. *See*, *National Mining Ass'n v. EPA*, 59 F. 3d 1351 (D. C. Cir. 1995); *Chemical Mfrs. Ass'n v. EPA*, 70 F. 3d 637 (D.C. Cir. 1995); *Clean Air Implementation Project v. EPA*, 1996 WL 393118 (1995). EPA announced its intent to conduct a comprehensive rulemaking to address the holdings in these cases, but has not yet taken action almost 30 years after the decisions were handed down. Memorandum from John S. Seitz to Regional Office Addressees, *Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit* (Jan 22, 1996) at 1.

With this as a backdrop, it is commendable for EPA to propose to clarify applicability of the storage vessel emissions standards by defining the term "legally and practicably enforceable limit." But this issue has implications that go far beyond the narrow confines of the storage vessel standard. Addressing it in a piecemeal, rule-by-rule fashion will ultimately cause confusion and potential inconsistency across the relevant programs. Further, it could inadvertently call into question existing permitting and regulatory regimes that do not specifically include the parameters proposed by EPA.

Moreover, affected facilities and states now have years of experience implementing the Subpart OOOO and OOOOa storage vessel standards, including substantial experience in crafting appropriate emissions limitations to govern applicability of these standards. Creating new mandatory procedural requirements is unnecessary, given that no systemic problem has emerged during this long implementation period. Such requirements would add to the cost and burden of implementing these standards without delivering any commensurate benefit.

Therefore, we suggest that EPA defer final action on the proposed definition until such time as the Agency undertakes a broad-based rule that would provide a single, consistent approach across all affected CAA programs.

11.9 The requirement to use "non emitting" equipment or methods does not constitute a "zero emissions" numeric standard.

Numerous times in the Proposal EPA describes non-emitting equipment or work practice standards as "zero-emissions" standards. For example, for liquids unloading, EPA is "proposing a standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions."). 86 Fed. Reg. at 63179. For pneumatic controllers, EPA is "proposing a requirement that all controllers (continuous bleed and intermittent vent) in the production and natural gas transmission and storage segments must have a methane and VOC emission rate of zero.". *Id*. at 63202.

As a practical matter, the term "zero-emissions" is apt because the object of these proposed standards is to eliminate methane and VOC emissions from the affected facility. But as a legal matter, the term "zero-emissions" is imprecise and in error because these standards impose equipment or work practice obligations and do not impose a numeric emissions limitation of zero.

The legal distinction is important because a fully compliant pneumatic controller or liquids unloading event may still have incidental VOC and methane emissions. No piece of equipment or work practice is perfect – even if implemented according to best practices. Thus, the term "zero-emissions" expresses an idealized outcome that is belied by reality. A zero-emissions numeric standard would unreasonably cause incidental emissions to be a violation of the standard. EPA should correct its terminology in the Final Rule by stating that non-emitting control measures under this rule are work practices.

11.10 Emissions due to noncompliance should not be treated as "fugitive emissions" under the rule as proposed.

EPA proposes that the term "fugitive emissions component" should include "[c]ontrol devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, State rule, or permit." *Id*. at 63170. EPA asks for comment "on the use of the fugitive emissions survey to identify malfunctions and other large emission sources where the equipment is not operating in compliance with the underlying standards, including the proposed requirement to perform a root cause analysis and to take corrective action to mitigate and prevent future malfunctions." *Id*.

This proposal to expand the definition of "fugitive emissions component" to include emissions from control devices not operating in compliance with applicable rules must be clarified. All other equipment included in the definition of "fugitive emissions component" is not expected to leak (at least in any significant amount). As a result, when periodic leak monitoring is conducted, the goal is to discern the presence of a leak.

In contrast, even well operating emissions control devices and flares will have a permissible level of emissions. Thus, a periodic LDAR-type emissions survey should be expected to detect some amount of methane or VOC emissions.

That raises the question of what amount of emissions triggers the need for further action under the LDAR work practices, such as investigation and corrective action? The conceptual answer is an amount that represents noncompliance with applicable emissions or work practice standards. But the Proposal does not describe a mechanism for determining what level of emissions corresponds to compliant conditions and how to determine the increased amount that represents actionable noncompliance. In other words, the rule does not define what constitutes a "leak" for purposes of emissions control devices or flares. To be workable, EPA must include such details in the final rule.

We note that an operator cannot tell whether a control device is meeting its designed control or destruction efficiency (often 95 or 98 percent) through use of an OGI camera because an OGI camera does not quantify emissions. Thus, it is not possible to determine from an OGI survey whether a control device is operating at its required efficiencies. At best, an operator may be able to obtain information from an OGI camera that suggests further investigation may be necessary to determine whether a device is functioning as intended. But even this limited concept would pose significant questions as to how it might be implemented (*e.g.*, permissible emissions from a control device often vary considerably due to variable loading).

In addition, OGI and M21 are not even feasible for flares. EPA needs to explain how these methods would apply or, conversely, prescribe acceptable and workable alternative methods.

For these reasons, we urge the Agency in the upcoming supplemental proposal to explain further how the LDAR program would apply to emissions control devices and flares.

11.11 When work practice standards are fully implemented, emissions addressed by those standards cannot constitute a "violation."

EPA suggests in the Proposal that, when a leak is detected in a closed vent system during a fugitive emissions survey, "the emissions would be considered a potential violation of the no detectable emissions standard." *Id*. This is a variation of the "zero-emissions" issue described in Section 1.9, above. The "no detectable emissions standard" is a work practice standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as detectable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. EPA has presented no reason in the Proposal to depart from its historical approach with regard to fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in compliance when a leak is detected, as long as the associated work practices requiring investigation and repair are followed.

11.12 The proposal fails to explain and appropriately reconcile the applicability of Subparts OOOO, OOOOa, OOOOb, and OOOOc.

The Proposal is notably silent on the question of how to reconcile the applicability of the three new source NSPSs and the existing source program. The only clues as to EPA's thinking are the proposed applicability dates for the various subparts. For example, Table 1 lists the applicability dates for the new source standards (Subparts OOOO, OOOOa, and OOOOb) for new, modified or reconstructed sources that trigger these rules. 86 Fed. Reg. at 63117. Similarly, Table 1 indicates that the Subpart OOOOc existing source program applies to sources in existence on or before November 15, 2021. *Id*.

These dates alone do not adequately explain how EPA proposes to apply the rules. For example, the Proposal could be interpreted such that sources already subject to Subpart OOOO or OOOOa as of November 15, 2021 become "existing sources" on that date and will be subject to the Subpart OOOOc existing source program.

On the other hand, the Proposal could be interpreted such that sources already subject to Subpart OOOO or OOOOa as of November 15, 2021, are "new sources" under those rules and, therefore, they are not somehow transformed into "existing sources" on November 15, 2021.

This applicability issue is further clouded by the fact that Subpart OOOO applies only to VOCs, Subparts OOOOa and OOOOb apply to VOCs and GHGs, and Subpart OOOOc applies only to methane. Thus, if EPA intends that all sources for which construction, reconstruction, or modification is commenced prior to November 15, 2021, should become existing sources subject to Subpart OOOOc, that outcome would apply only for purposes of GHGs. To the extent such sources already were subject to Subpart OOOO or OOOOa, they would continue to be subject to those subparts for purposes of VOCs.

API has two recommendations on these issues. First, in the upcoming supplemental proposal containing proposed regulatory text, EPA must clearly propose how it intends to reconcile applicability of the various subparts. Applicability is a critical issue that cannot be left unaddressed or ambiguous.

Second, API recommends that there is only one permissible approach under CAA § 111, which would be comprised of two basic rules. First, a "new source" that is subject to Subpart OOOO, OOOOa, or OOOOb cannot be subject to the Subpart OOOOc existing source program. Second, and by extension, the Subpart OOOOc existing source program applies only to sources that were not subject to Subpart OOOO or OOOOa as of November 15, 2021[71] – i.e., the Subpart OOOOc existing source program applies only to sources that were not regulated by a relevant subpart as of November 15, 2021.

This outcome is required by two provisions in CAA § 111. First, the term "new source" is defined to mean "any stationary source, the construction or modification of which is commenced after the publication of regulation (or, if earlier, proposed regulation) prescribing a standard of performance under this section which will be applicable to such source." CAA § 111(a)(2). Because Subparts OOOO and OOOOa are "regulations" that "prescribed standards of performance" for affected facilities at "stationary sources," any affected facilities under Subparts OOOO or OOOOa unambiguously must be "new sources" under this definition. It does not matter that EPA has promulgated (and plans to promulgate) successive versions of the new source standard and it does not matter that the proposed Subpart OOOOc existing source program post-dates Subparts OOOO and OOOOa. Under the plain terms

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[71] API explains above that November 15, 2021, is not a permissible trigger date for Subparts OOOOb and OOOOc because the Proposal is not actually a proposed rule. API neither waives that position nor concedes that point here.

of the statutory definition of "new source," affected facilities under Subpart OOOO or OOOOa are "new sources.

Second, this point is driven home by CAA § 111(d), which states (in relevant part) that EPA shall prescribe regulations establishing a program for "any existing source … to which a standard of performance under this section would apply if such existing source were a new source." CAA § (d)(1)(A). This provision unambiguously directs that a CAA § 111(d) existing source program may apply only to an existing source that is not subject to a standard of performance for new sources. This necessarily follows from the definition of "new source."

11.13 EPA is not authorized to approve state existing source emissions limitations that were not derived using the required CAA § 111 standard-setting methods.

EPA proposes "[t]o the extent a State chooses to submit a plan that includes standards of performance that are more stringent than the requirements of the final EG, States have the authority to do so under CAA section 116, and the EPA has the authority to approve such plans and render them Federally enforceable if all applicable requirements are met. Union Electric Co. v. EPA, 427 U.S. 246, (1976)." 86 Fed. Reg. at 63251. EPA notes that "in the Affordable Clean Energy (ACE) rule, it previously took the position that Union Electric does not control the question of whether CAA section 111(d) State plans may be more stringent than Federal requirements." *Id*. But EPA "no longer takes this position." *Id*. "[B]ecause of the structural similarities between CAA sections 110 and 111(d), CAA section 116 as interpreted by Union Electric requires the EPA to approve CAA section 111(d) State plans that are more stringent than required by the EG if the plan is otherwise is compliance with all applicable requirements." *Id.* at 63251-2.

EPA further explains that "CAA sections 111(d) and 110 are structurally similar" and that "[r]equiring States to enact and enforce two sets of standards, one that is a federally approved CAA section 111(d) plan and one that is a stricter State plan, runs directly afoul of the court's holding that there is no basis for interpreting CAA section 116 in such manner." *Id.* at 63252. EPA concludes by noting that "its authority is constrained to approving measures which comport with applicable statutory and regulatory requirements. For example, CAA section 111(d) only contemplates that State plans include requirements for designated facilities, therefore the EPA believes it does not have the authority to approve and render federally enforceable measures on other entities." *Id*.

As EPA notes, the Agency took the diametrically opposite position in the ACE rule. "In response to commenters who contend the EPA does not have the authority to approve more stringent state plans," EPA agreed that the comments have merit. 84 Fed. Reg. 32520, 32559 (July 8, 2019). EPA provided a detailed explanation:

> [T]he Court's decision in Union Electric on its face does not apply to state plans under CAA section 111(d). The decision specifically evaluated whether the EPA has the authority to approve a SIP under section 110 that is more stringent than what is necessary to attain and maintain the NAAQS. The Court specifically looked to the requirements in CAA section 110(a)(2)(A) as part of its analysis, a provision that is wholly separate and distinct from CAA section 111(d). CAA section

> 110(a)(2)(A) requires SIPs to include any assortment of measures that may be necessary or appropriate to meet the ''applicable requirements'' of the CAA, which largely relate to the attainment and maintenance of the NAAQS. CAA section 111(d), by contrast, directs state plans to establish standards of performance for existing sources that reflect the degree of emission limitation achievable through the application of the BSER that EPA has determined is adequately demonstrated—and CAA section 111(d) expressly provides that it cannot be used to regulate NAAQS pollutants. Because the Court's holding was in the context of section 110 and not CAA section 111(d), the EPA believes that Union Electric does not control the question of whether CAA section 111(d) state plans may be more stringent than federal requirements.

Id. at 32560.

To sum up, two years ago EPA asserted that *Union Electric* is not applicable to state plans submitted under CAA § 111(d) because that case dealt only with state emissions standards adopted under CAA § 110. Moreover, emissions standards prescribed by CAA § 111 are materially different than state implementation plans submitted under CAA § 110. The former must be based on BSER, which is narrowly and precisely defined in the Act. The latter must be designed to satisfy minimum statutory requirements designed to achieve the broader air quality goals of attaining and maintaining compliance with the NAAQS.

Today, EPA proposes that *Union Electric* is applicable to state plans submitted under CAA § 111(d) because that provision and CAA § 110 are "structurally similar in that States must adopt and submit to the EPA plans which include requirements to meet the objectives of each respective section." 86 Fed. Reg. at 63252. EPA notes that the *Union Electric* court was concerned that, if more stringent state programs could not be approved under CAA § 110, then states that wanted to be more stringent would need to have two sets of regulations in place – a less stringent EPA-approved version and a more stringent state-only-enforceable version. The court concluded that such an approach was not warranted because it would impose "wasteful burdens" on EPA and the states. EPA argues that the same rationale equally applies to state CAA § 111(d) programs.

These opposing views are easily resolved by looking at what the court actually said in *Union Electric*. That case involved a 1972 Missouri state implementation plan ("SIP") for sulfur dioxide. *Union Electric Co. v. EPA*, 427 U.S. 246, 252 (1976). A local utility filed a challenge to that SIP claiming that the SIP was invalid because it imposed technologically and economically infeasible emissions control requirements. *Id*. at 253.

The court upheld the SIP on the grounds that "Congress intended claims of economic and technological infeasibility to be wholly foreign to the Administrator's consideration of a state implementation plan." *Id*. at 256. More specifically, the court interpreted "the 'as may be necessary' requirement of § 110(a)(2)(B) to demand only that the implementation plan submitted by the State meet the 'minimum conditions' of the [1970 CAA] Amendments." *Id*. at 264. "Beyond that, if a State makes the legislative determination that it desires a particular air quality by a certain date and that it is willing to force technology to attain it – or lose a certain industry if attainment is not possible – such a determination is fully consistent with the structure and purpose of the Amendments, and § 110(a)(2)(B) provides no basis for the EPA Administrator to object to the determination on the ground of infeasibility." *Id*. at 265.

Thus, the court expressly held (as EPA observed in 2019) that CAA § 110(a)(2)(B) allows states to adopt more stringent programs than minimally required by the Act. In that context, its observation that CAA § 116 should not be read as only authorizing more stringent state-only emissions control programs, *id.* at 264, is limited to programs such as CAA § 110 that, in the first instance, allow states to adopt more stringent measures than minimally required under the Act.

Here, CAA § 111(d) unambiguously requires state existing source programs to prescribe "a standard of performance," which is defined to mean "a standard for emissions of air pollutants which reflects the degree of emissions limitation achievable through the application of the best system of emissions reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." CAA §§ 111(d)(1)(A) and 111(a)(1). There is no room for states to do anything more than prescribe standards of performance that reflect BSER. Thus, in sharp contrast to CAA § 110, CAA § 111(d) does not prescribe "minimum conditions" that may be exceeded by the states. Instead, CAA § 111(d) requires standards of performance that must reflect a BSER determination that is based, among other things, on consideration of costs and feasibility. If proposed state standards of performance do not meet these requirements, they must be rejected by EPA.

Therefore, "structural similarities" between CAA §§ 110 and 111 do not provide an adequate basis for EPA's proposal that it may approve state standards of performance that are more stringent than required by CAA § 111(d). Such an approach unreasonably and unlawfully ignores the significant substantive differences between CAA §§ 110 and 111 and would violate the unambiguous requirement that state § 111(d) standards of performance <u>must</u> reflect BSER.

To be clear, API supports the coordination and consolidation of federal and state emissions control requirements for the oil and gas sector. Ideally, only one set of standards would apply – state devised and administered emissions control programs that simultaneously satisfy CAA § 111 requirements and address any unique state priorities and objectives. We believe there is sufficient latitude under CAA § 111(d) to allow for EPA approval of state programs in most cases because, in our experience, state programs are typically grounded in principles that would satisfy CAA § 111 standard setting criteria.

But it is at least theoretically possible that a state would seek to impose emissions control obligations that go so far beyond CAA § 111 principles that such obligations cannot be squared with the federal CAA requirements. In such cases, states have authority under CAA § 116 to implement their programs as a matter of state law. But there is no authority under CAA § 111 or 116 for EPA to federalize such state programs.

Attachment A

API Comments on Prepublication Draft Appendix K – Protocol for Using Optical Gas Imaging to Detect Volatile Organic Compound and Greenhouse Gas Leaks

API Comments on Prepublication Draft
Appendix K – Protocol for Using Optical Gas Imaging to Detect Volatile Organic Compound and Greenhouse Gas Leaks[1]

I. General Comments on Proposed Appendix K Draft

1. API supports use of Optical Gas Imaging (OGI) technology because of its potential to reduce equipment leak emissions at a lower cost than through use of traditional methodologies. However, significant modifications are necessary to the proposed Appendix K protocol.

API has worked diligently with EPA to integrate OGI monitoring into rules and to develop the specifics of the methodology. These comments are intended to foster a high-quality generic methodology for use at facilities with large process operations.

API believes significant modifications (as offered herein) to the proposed Appendix K are necessary before it could effectively be implemented for use across downstream oil and gas facilities or other process industries. API's recommended changes are intended to proactively address concerns that the proposed requirements:

1) will result in difficulty in finding and retaining, adequate numbers of qualified senior OGI operators;

2) that the monitoring, training and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and

3) that the ownership of various requirements, and particularly the recordkeeping requirements, are unclear and unnecessarily burdensome.

API's recommended changes also aim to make the Appendix K requirements more straightforward and efficient.

2. Appendix K requirements, even if revised, are not appropriate for most upstream and midstream operations characterized by a great many small, geographically dispersed and often remote facilities, with a limited number of fugitive equipment components.

Appendix K as drafted is unnecessarily burdensome and ineffective for utilization in upstream production facilities, gathering and boosting compressor stations, and transmission compressor stations as discussed in the main body of API's comments on this proposal[2]. OGI protocols for these facilities

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[1] Posted at https://www.epa.gov/system/files/documents/2021-11/40-cfr-part-60-appendix-k-proposal_0.pdf

[2] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review: Proposed Rule 86 *Fed. Reg*. 63110 (November 15, 2021)

should continue to be based on part 60 subpart OOOOa requirements, not Appendix K. The requirements specified in subpart OOOOa that are currently used by operators have consistently proven to be effective and are more appropriate for use in upstream applications.

Appendix K goes beyond the current subpart OOOOa requirements concerning performance specifications, operating envelope, survey time, and records for leaking components and is impractical for upstream operators to implement given the hundreds to thousands of well sites and compressor stations to monitor, the geographic dispersion of these facilities and the lack of on-site resources.

3. Appendix K methodology may be suitable for large, complex process operations in other industries.

A. Proposed Appendix K provides a protocol for performing OGI surveys at complex process operations, such as refineries. It is potentially applicable, with the changes we are recommending, not only for refineries and gas plants, but for many similar, complex processes. On promulgation of Appendix K, permitting authorities are likely to immediately begin requiring its use for a variety of such processes. Furthermore, if the final methodology is resource and cost efficient, many facility owners or operators will apply for approval to use OGI as an alternative to current Method 21 monitoring.

Since the proposed Appendix K clearly identifies in proposed paragraphs 6.1.1 and 6.1.2 where a particular OGI camera is sensitive enough to find leaks and rulemaking or Administrator approval would be needed to allow use of OGI for a process not covered by the current rulemaking, it seems counterproductive to include in Appendix K itself a limitation to only oil and gas source categories. Thereby preventing or delaying, others from realizing the benefits of using OGI. We provide additional specifics and our recommendations in Comment II.2.

B. Assuming reasonable frequency and repair requirements are proposed and our suggested revisions to the proposed Appendix K are implemented, we recommend EPA proceed expeditiously to amend part 63 subpart CC (RMACT 1) to allow use of OGI technology and Appendix K as an alternative to Method 21 for refineries. In the recent Refinery Sector Rulemaking, EPA proposed allowing for use of OGI as an alternative to Method 21, but did not finalize that proposal because "we have not yet proposed appendix K."[3] Adding OGI as an alternative to RMACT 1 would significantly reduce the refinery and Agency resources associated with preparing and reviewing Alternative Method of Emission Limitation or Alternative Monitoring requests to allow OGI for those facilities and allow refineries to take advantage of the improvements inherent in Appendix K versus the currently available leak detection and repair (LDAR) Alternative Work Practice (AWP) in Part 60 Subpart A (§60.18(g), (h) and (i)).

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[3] 80 *Fed. Reg.* 75191 (December 1, 2015)

4. Resource constraints could make OGI using Appendix K impractical and inefficient.

A. The proposed Appendix K protocol imposes overly burdensome monitoring, training, auditing and other QA/QC requirements that reduces the hours a camera operator can spend monitoring and extends the time it takes to qualify or requalify a camera operator. Training requirements associated with the Appendix K protocol could be reduced in API's view without sacrificing the effectiveness of emission detection efforts.

Additionally, Appendix K requires a senior OGI camera operator to train and oversee other OGI camera operators and in some cases to take videos of monitoring operations, requiring at least a senior operator for every 5-10 OGI camera operators doing actual monitoring. This is a problem for any user of Appendix K. We discuss this in more detail in paragraph B of this comment and throughout these comments.

The establishment of significant and excessive overhead by the proposed Appendix K compared to part 60 subpart OOOOa and other current OGI monitoring requirements reduces the economic advantage for moving to this alternative. OGI technology offers the potential to play a significant role in reducing methane and VOC emissions, reducing leak durations and lowering the cost of monitoring. Imposing additional overhead does not significantly increase leak detection and repair effectiveness, but does increase costs and inefficiencies.

B. A senior OGI camera operator is defined in Section 3.0 of the proposed Appendix K as a "camera operator who has conducted OGI surveys at a minimum of 500 sites over the entirety of their career, including at least 20 sites in the past 12 months, and has completed or developed the classroom, computer or on-line camera operator training as defined in Section 10.2.1."

Paragraph 10.2.2 requires a senior OGI operator to:

- conduct 10 surveys while being observed by a trainee,
- conduct 40 side -by-side surveys with each trainee,
- observe 50 surveys performed by the trainee, and
- perform a follow-up survey as a final test of a new trainee.

Thus, the senior OGI operator is tied up for the duration of trainee classroom training and for 101 surveys per trainee. Additionally, there are proposed quarterly performance audit requirements, which would require at least a day (two 4-hour surveys) of a senior OGI operator's time for each operator being audited. There will be a huge demand for senior OGI operators, and those operators will be doing training and audits rather than monitoring for leaks. While we recommend reasonable reductions in these individual duties that would still assure well-trained OGI camera operators conduct monitoring surveys, we believe the demand for senior OGI camera operators will exceed supply for the foreseeable future and will be an on-going challenge. Conceptually, our desire is to have our most experienced camera operators monitoring for leaks a significant portion of their time, not spending all their time training or auditing. That can only be accomplished if there is an adequate supply of such senior people and if those senior people have enough field monitoring time to keep their skills sharp.

We therefore recommend that, in addition to reducing the time senior operators must spend on training and auditing, the criteria for the senior OGI operator designation be revised. As we specifically address throughout these comments, we believe the functions planned for this operator category can be performed by OGI camera operators with a reasonable amount of current field experience, and such a change in the senior operator criterion will assure enough qualified people will be available to perform the necessary training and auditing functions. Furthermore, the resulting larger pool of senior operators would permit rotating personnel efficiently through monitoring, training and audit functions.

To accommodate this change, we suggest a revised definition of senior "OGI camera operator" in Comment II.6, which removes the requirement as to the career experience of the individual and converts the 20-site current experience requirement to 100 hours.

5. Use of drones as an OGI camera platform

Drones are currently being developed, and in some cases, being used to perform OGI monitoring. They are particularly useful and efficient for monitoring dispersed small sources (e.g., in tankfields) and elevated, hard to reach equipment. **We request that the rulemaking clarify that use of drones is allowed if Appendix K requirements are met and, as discussed in Comment II.1, by removing the limitation in Appendix K that the camera be "hand-held."** While the type of mount needs to be considered in determining if a separate operating envelope is needed for camera configurations used with that mount, this clarification should make it clear that if operating envelope, dwell time and related requirements appropriate for a particular camera model and configuration are met it does not matter how the camera is mounted. **To affect this clarification, we recommend drones be included as an example of a camera platform in the definition of camera configuration and in proposed paragraph 8.3.**

6. While not appropriate for inclusion in Appendix K, fixed continuous monitors should be addressed in referencing rules where appropriate.

In some situations, continuous leak monitoring systems are justified and starting to be used instead of periodic monitoring with portable OGI cameras. As discussed in the main body of these comments, where such systems might be desirable for some situations, the referencing subpart (in this case proposed subparts OOOOb and OOOOc) should address that approach as an alternative to periodic OGI monitoring.

II. Specific Comments and Recommendations on Appendix K

1. General Terminology

A. The OGI camera addressed by Appendix K is identified as a "hand-held, field portable infrared camera" throughout the proposal. Field portable cameras that are capable of being hand-held are sometimes mounted on tripods (as indicated in the draft definition of "Camera Configuration" and elsewhere in the proposal) or mounted on a drone, or are set down on a surface or mounted on a harness worn by the operator; those variants could be interpreted as not being "hand-held." Since operating envelopes can be developed for any of these mounting approaches, we believe it is more appropriate to specify that Appendix K addresses "field portable infrared cameras," and that it is unreasonable and adds significant inefficiency to require that the camera be hand-held. **We therefore recommend the modifier "hand-held" be deleted from Appendix K everywhere it occurs as a OGI camera descriptor.** Use of the term as an example of an OGI camera operating condition (e.g., in the definition of "Camera Configuration") is appropriate and need not be deleted, though we suggest "drone" be added as an alternative example of a camera mount in those two cases where "hand-held" and "tripod" are identified as example camera mounts.

B. Many places in Appendix K refer to "regulated components." But there will be locations where there are components regulated under other rules (e.g., a HON process unit located within a refinery) or by non-equipment leak portions of the referencing rule or permit (e.g., process vents) that might be within an OGI's operating envelope. **Thus, for clarity, we recommend the term "regulated components" be changed to "equipment leak components regulated by the referencing subpart or permit."**

C. In the petroleum operations that Appendix K would apply to under the current proposal[4] and in other operations it may apply to under other rules or permits, a "site" can be anything from a single piece of equipment involving a few potential leak interfaces to a refinery complex involving millions of potential leak interfaces. Thus, monitoring a "site" can take a brief time for one OGI operator (minutes or hours) or require many fulltime OGI operators and take months to complete. Because of this extreme diversity, **API recommends "site" not be the basis for any Appendix K requirements, except where the size of the site is not significant** (e.g., the requirement in Section 9.0 that each "site" have a monitoring plan)**.** Specific suggestions for alternatives to each use of "site" in the draft Appendix K where we believe a change is needed are included below and in the redline version of the proposed Appendix K we have included with these comments.

Additionally, there are requirements assigned to the "site" that could be the responsibility of a contract monitoring organization and could apply at multiple sites. For instance, development of procedures that describe how components will be viewed with the OGI camera (paragraph 9.4) and the requirement to have a plan for avoiding camera operator fatigue (paragraph 9.5). **In these cases, we are recommending that Appendix K provide that the various requirements assigned to the site be either**

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[4] Ibid.

reassigned or flexibility be provided to allow a more appropriate assignment of responsibility and to reduce unnecessary or duplicative recordkeeping requirements.

D. "Number of surveys" performed is a proposed criterion for an operator to be a senior OGI operator, for establishing training requirements and is a criterion for other proposed requirements. Given that an individual site survey can take hours or months depending on the size and complexity of the site, basing any requirement or criterion on the "number of surveys" creates confusion and inequities. In our specific comments below, **we recommend use of hours of monitoring or, in some cases, the "number of 20-minute monitoring periods" as a more precise and easily managed substitute for "number of surveys."**

E. In setting requirements based on "sites" or "number of surveys" there is a lack of clarity as to whether the requirements require each site to be a different site or each survey to be of a separate set of equipment. This concern would carry over if, as we recommend, the criterion is changed to a monitoring time basis. It would be burdensome and wasteful to interpret these requirements as requiring monitoring of different equipment and, in some cases, it would be infeasible to meet such an interpretation. **We recommend EPA clarify that such requirements do not require monitoring of different equipment for every survey, and we have recommended clarifying language in some of our specific comments and in our redline version of the proposed Appendix K.**

F. Initial training requirements for OGI operators is referred to as "classroom" training throughout proposed Appendix K. Most training today is done through electronic media, often through web-based on-line modules. Use of the word "classroom" could be interpreted to disallow such common training approaches and instead mandate in person classroom attendance. Such a strict limitation creates inefficiencies, is inconsistent with modern training approaches and potentially limits the rate at which new operators can be trained. **API requests the word "classroom" be deleted or revised everywhere it is used.** In some uses we believe the meaning is unchanged by this deletion, but where necessary we suggest the term "classroom, computer or on-line" be used instead.

2. Paragraph 1.3 Applicability Belongs in a Referencing Subpart, Not in A Test Protocol

A. Paragraph 1.3 starts "This protocol is applicable to all facility types from the upstream and downstream oil and gas sectors and may apply to well heads, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities when referenced by an applicable subpart." Consistent with the application of Appendix K to other source categories in the near term, the precedent of leaving applicability decisions to referencing subparts and permits, and API's belief that Appendix K is inappropriate for many of the upstream operations listed, we see no purpose for including this sentence in Appendix K. Nor does it reflect that the protocol addresses equipment leaks, as would be normal for an EPA method. **API, therefore, recommends this sentence be revised to the following: "This protocol is applicable to equipment leak components at facilities when referenced by an applicable subpart."**

B. Paragraph 1.3 states “This protocol is not applicable to chemical plants or other facility types outside of the oil and gas upstream and downstream sectors.” **We recommend this sentence be deleted.** Appendix K is appropriate for use for some processes in other source categories and there is no reason to preclude that here since Appendix K only becomes applicable when a referencing subpart, permit or the Administrator allows and since adequate camera capability is assured by the requirements in proposed Paragraphs 6.1.1 and 6.1.2.[5] and the other Appendix K requirements.

For instance, there are many Hazardous Organic NESHAP (HON) processes, including within some refineries (e.g., benzene, toluene, xylene (BTX) units), where Appendix K would be immediately useable, with appropriate approvals. There is no reason to preclude the use of OGI and Appendix K, and to forgo any potential emission reductions or efficiencies, for those HON processes where the camera has adequate capability by having this sentence present in Appendix K. Similarly, Appendix K could, with appropriate approvals, be used for Ethylene Production source category units, another type of unit often found within or adjoining a refinery. Deleting this sentence now, would save having to amend Appendix K in the near future, when the first non-oil and gas rule is proposes to allow OGI, or a regulatory authority wishes to require its use for other source categories.

While there will be processes in a chemical or other source category where OGI and Appendix K would not fit, there are many places where it does and the use of OGI in those cases should be encouraged. Assurance that Appendix K is not being misapplied can be further achieved by being specific in the referencing subpart or permit as to process chemistry that must be present to use OGI and Appendix K, or through the permit or Administrator review where it is requested to be used for sources not covered by a referencing subpart. The purpose of part 60 appendices is to provide generic methodologies that do not have to be amended each time they are referenced, and we encourage the Agency to align the Appendix K applicability section with that purpose.

3. Definition of “Fugitive Emission or Leak”

The proposed definition of fugitive emission or leak is “any emissions observed using OGI.” **API believes that the definition can only address emissions from equipment components identified in the referencing subpart or permit as being subject to OGI.** Those are the only emission sources that were considered in the referencing subpart rulemaking or permitting process and are the only components that the referencing subpart or permit monitoring and repair provisions address. We agree that other OGI findings must be addressed if the monitoring identifies excess emissions or unauthorized emissions, but such findings are subject to other repair and reporting requirements than those a referencing subpart or permit imposes for equipment leaks.

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[5] 6.1.1 The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition

6.1.2 The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr.) and butane emissions of 18.5 g/hr. at a viewing distance of 2 metersand a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less.

We recommend the following revised definition.

> ***Fugitive emission or leak* means any emissions observed using optical gas imaging from any equipment component identified in the referencing subpart or permit as being subject to monitoring using this Appendix (Appendix K).**

4. Definition of "Repair"

Appendix K appropriately requires that when a leak is identified by OGI monitoring, that the leaking component be clearly identified. However, Appendix K does not address repair. Repair requirements are addressed in the referencing subpart or permit, and the referencing subpart or permit may provide alternatives to adjusting or altering the leaking component, the only approach mentioned in the proposed Appendix K definition of repair. For instance, it may be possible and allowed to route the leak to a compliant control device. Additionally, the referencing subpart will have its own definition of repair and will address how it is to be demonstrated that the repair was successful. For instance, it could require remonitoring by OGI or it could require remonitoring by OGI or Method 21. **Because repair is addressed in each referencing subpart or permit and not in Appendix K, and the definition in that subpart or permit may be different from the definition proposed here, this proposed definition should be deleted.**

5. Definition of "Response Factor"

The proposed definition of "response factor" is:

> *Response factor* means the OGI camera's response to a compound of interest relative to a reference compound at a concentration path-length of 10,000 part per million-meter. Response factors can be obtained from peer reviewed articles or may be developed according to procedures approved by the Administrator.

The second sentence of this proposed response factor definition limits response factors to those obtained from peer reviewed articles or developed according to procedures approved by the Administrator. However, there are serious issues with that limitation as discussed below. We believe that the criteria in the first sentence of the proposed definition and in paragraph 6.1.1 of the proposed Appendix K are adequate to assure valid response factors. Therefore, **API recommends that the second sentence of the proposed definition be deleted.**

The first issue is that there may be different response factors for different OGI cameras as technology changes and new response factors will be needed as additional applications of OGI are made. Such commercial information is not amenable to publication in peer reviewed articles, nor could such response factors be published in a timely manner. Thus, if anything is to be peer reviewed it must be the methodology used to develop the response factors. Given the specifics in the first sentence (a path-length of 10,000 ppm-meters) and the specification in proposed paragraph 6.1.1 of propane as the reference compound, it hardly seems necessary to require any review of the response factors themselves.

Secondly, hundreds of response factors have been developed by camera manufacturers for current cameras. We are concerned that those response factors, which are currently in widespread use, might not meet the criteria in the proposed definition. While these factors may have been peer reviewed, they were not necessarily "obtained from peer reviewed articles." Furthermore, we have no idea what procedures the Administrator might require and whether currently used factors will be found to be consistent with that yet undefined procedure.

If the Agency believes such a limitation is needed, it should focus the limitation on the methodology for developing response factors, propose the methodology they plan to require when the final Appendix K language is proposed, provide for automatic approval after 90 days of any response factor or response factor methodology submitted to the Administrator if no action is taken within that time and grandfather response factors developed prior to the proposal of the Administrator's methodology.

6. Definition of "Senior OGI Camera Operator"

A. Some OGI camera operators are certified thermographers. The thermographic certification requirements for a Level 2 thermograph operator parallel the initial and refresher OGI training requirements that would apply under Appendix K. Thus, **we recommend that certified thermographers be considered as senior OGI camera operators and that they be exempted from the initial training requirements in proposed Paragraphs 10.1 through 10.3.**

To this end, we also recommend adding a definition of a certified thermographer as follows:

> ***Certified Thermographer* for the purposes of this Appendix, means a thermographer who has successfully completed the requirements for a Level 2 or higher thermography certificate compliant with ASNT-TC-1A or ISO 18436-7.**

B. Our members report confusion over the 12-month time (i.e., whether it is a calendar 12-months or a rolling 12-months) in the proposed senior OGI camera operator definition. **We recommend, as included in our recommended revised definition below, a sentence be added to the definition of senior OGI camera operator to clarify this point as follows "Previous 12-months means the 365-calender days prior to the day of the activity requiring a senior OGI camera operator."**

C. **Per the discussion in Comment I.4.B, we recommend the proposed definition of senior OGI camera operator be replaced. We suggest the following definition:**

> **A senior OGI camera operator is an OGI camera operator who has performed at least 100 hours of OGI monitoring (excluding their own initial and refresher training time) in the previous 12-months and has either 1) successfully completed the initial and field training specified in Section 10 of this Appendix and has completed any required refresher training or**

2) is a certified thermographer. Previous 12-months means the 365-calender days prior to the day of the activity requiring a senior OGI camera operator.

As discussed in comment II.1.C, "site" is an extremely unclear and imprecise term and we are suggesting that 100 hours of recent monitoring experience (i.e., in the previous 12 months) be specified instead. More critically, we are recommending removal of any "career" experience requirement. We do not believe career experience adds significantly to an operator's ability to train or audit others. It is recent experience with current equipment and requirements at locations of the type currently being monitored that is critical to quality training and auditing, and we believe a 12-month criterion provides that expertise. Removing the proposed career criterion will increase the availability of senior OGI camera operators as OGI programs are being instituted and the demand for senior operators is at a maximum for training purposes and will make some senior operators available for actual monitoring duty.

One hundred hours of monitoring experience is consistent with the results of the operator experience testing reported in the Appendix K Technical Support Document (TSD)[6]. As shown in Table 4-35 (Overall Blind Survey Results for Leaks Released at 2% Concentration) and Appendix C-3 of the TSD, there was little difference among camera operators above the novice level (<10 hours of monitoring experience). In fact, the two most experienced operators (with >300 hours of field experience and >400 hours of laboratory experience) had the worst and the best results at finding leaks, respectively. The other operators did about equally well and had experience levels at or under 100 hours and some had no field monitoring experience at all. This conclusion is supported by others. In Appendix 1 to the Optical Gas Imaging Feasibility Study Summary Report included in the Appendix K TSD[7], it is reported that a Sage Environmental expert interviewed by EPA's contractor stated, "that a trusted operator (one who has sufficient imaging experience to generate highly reliable results) has about 1 month or 100 hours of in-the-field use and experience." Similarly, Texas has concluded that refresher training is not needed for an OGI camera operator with 100 hours in 12-months experience[8], an indication that that level of experience identifies a well-qualified individual.

The work of Zimmerle, et. al.[9] referenced in the TSD evaluated operator experience levels using test facilities typical of upstream equipment. They concluded that "Surveyors from operators/contractors who had surveyed more than 551 sites prior to testing detected 1.7 (1.5–1.8) times more leaks than surveyors who had completed fewer surveys" but they also point out their "data also indicate that all surveyors have a high probability of detecting large leaks" and thus "it is unclear if total emissions (which are generally dominated by large emitters) would be highly impacted." While there is some variability, the data reported by Zimmerle, et. al. appears to show that their 551-site finding is equivalent to 200-250 hours of monitoring. We believe any operator meeting the >100 hour/12-month criterion we recommend would already have or quickly pass the 200-250 hours of experience and that

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[6] Docket Document EPA-HQ-OAR-2021-0317-0079, Eastern Research Group, Technical Support Document: Optical Gas Imaging Protocol, August 2, 2021, Pages 113 and 114

[7] Ibid.

[8] See 30 TAC 115.358(h)(2).

[9] Zimmerle, D., Vaughn, T., Bell, C., Bennett, K., Deshmukh, P., & Thoma, E. (2020). Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. Environmental Science & Technology, 54(18), 11506-11514. DOI: 10.1021/acs.est.0c01285

emission reduction effectiveness would not be seriously impacted in the interim because large leaks will be readily found by any camera operator.

Our recommended level of experience will assure the senior OGI camera operator duties are well performed and that their knowledge is current while expanding the pool of senior operators to assure an adequate supply and the availability of senior operators to perform monitoring as well as training and quality assurance functions.

It also should be clarified that monitoring hours performed by a senior operator as a quality check of another operator or as part of operator training counts toward the 12-month senior OGI operator monitoring criterion.

D. The proposed definition would seem to require that a senior OGI camera operator must have conducted OGI surveys at 500 different sites in their career and 20 different sites in the past 12 months. We recommend below this criterion be changed to a “hours in the previous 12-months” basis. None-the-less, many OGI camera operators, particularly those associated with a single company or facility, will not have access to many different sites or be able to monitor 100 hours at separate locations. Thus, as recommended in general in Comment II.1.E, **EPA should clarify that any field monitoring counts towards the senior operator’s site or hour’s criterion, whether at the same or separate locations, except for the senior operators own initial and refresher training hours.**

7. Paragraph 5.1 Site Hazards

The final sentence of this paragraph states, “It is the responsibility of the user of this protocol to establish appropriate health and safety practices and determine the applicability of regulatory limitations prior to implementing this protocol.” **This sentence is inappropriate and unnecessary and should be deleted.** Imposing health and safety requirements, even general ones such as this, is the responsibility of other Agencies.

Furthermore, it is the responsibility of all involved, not just the user of this Appendix to assure a safe and healthy operation. It is EPA’s responsibility not to incorporate unsafe requirements into this method. It is the responsibility of the site owner or operator to meet requirements applicable to the site and to establish other requirements it feels are needed. It is the responsibility of the OGI camera operator and his or her organization to meet regulatory and other requirements applicable to workers.

8. Section 6 Equipment and Supplies

A. **API supports the spectral range requirements in paragraph 6.1.1.** In refineries and other complex processes likely to eventually become subject to Appendix K, monitored components can contain many hydrocarbons with a range of individual response factors. It is important to making the OGI methodology feasible for these processes to balance the camera’s ability versus the range of components that may be in an emission and our limited ability to precisely characterize stream compositions. We believe the proposed paragraph accomplishes that balance and cameras meeting this specification will be widely applicable and will be able to identify emissions of these materials and thus assure equipment leak emissions are controlled. For upstream operations there is usually a dominant hydrocarbon in the streams being monitored and, therefore, the simpler, less burdensome requirement in §60.5397a(c)(7)(i)(A) is appropriate for those operations.

B. Paragraph 6.1.2 and its subparagraphs specify a minimum camera detection limit for methane and butane and various equipment to be used in demonstrating that those minimum limits are met. Requiring this test for every individual OGI camera is unnecessary since all cameras of a particular model are the same. Some camera configuration changes, as exemplified in the definition of camera configuration can impact detectability (e.g., changes sensitivity setting or camera lens) while other will not (e.g., whether camera is hand-held or mounted on a tripod). Thus, the detection limit demonstration is only needed for each configuration that could impact the detection limit. **We recommend that paragraph 6.1.2 be clarified to indicate that this testing may be performed by the equipment manufacturer for each model camera and for each configuration where a camera configuration parameter could impact the camera detection limit and that this demonstration does not have to be performed for every individual OGI camera.**

C. It is proposed in paragraph 6.1.2 to establish the minimum camera detection limit as detection of 17g/hr. methane and 18.5 g/hr. butane at specific distance, delta T and wind conditions. This is a change from the 60g/hr. (10,000 ppm methane/propane mix) minimum detection limit established in part 60 subpart OOOOa and that is in general use today. EPA explains in the proposal that 17g/hr. is what their current modelling shows is needed from bimonthly OGI to get the same emission reduction for methane as is achieved by subpart OOOOa Method 21 requirements[10] . It was shown previously that the subpart OOOOa OGI requirement is also equivalent to Method 21[11]. Thus, there does not seem to be any reason for changing the minimum detection limit demonstration (and possibly having to replace some cameras), requiring new operating envelope determinations, and potentially requiring changing procedures and permits that already use the OOOOa requirements. **API, therefore, recommends the minimum detection limit requirement from §60.5397a(c)(7)(i)(B)[12] be allowed as an alternative to the proposed paragraph 6.1.2 minimum detection limit and that the operating envelope determination procedure in paragraph 8.5 be revised accordingly.**

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[10] Op. Cit., page 63232

[11] Environ. (2004). Development of Emissions Factors and/or Correlation Equations for Gas Leak Detection, and the Development of an EPA Protocol for the Use of a Gas-imaging Device as an Alternative or Supplement to Current Leak Detection and Evaluation Methods. Final Report to the Texas Council on Environmental Technology and the Texas Commission on Environmental Quality.

[12] Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr. from a quarter inch diameter orifice.

D. To clarify the recordkeeping requirements associated with paragraphs 6.1.1 and 6.1.2 and to eliminate what could be viewed as a requirement for large volumes of unnecessary records, **we recommend that proposed second sentence of paragraph 8.1 be relocated to section 6 as 6.1.3 and that it require paragraph 6.1.2 records to be maintained by the organization doing the demonstration (usually the camera manufacturer)** and not by every site where that camera is being used. **We propose:**

> **6.1.3 Documents demonstrating compliance with paragraphs 6.1.1 and 6.1.2 must be retained with other OGI records by the owner or operator or testing organization, as applicable.**

E. Paragraph 6.2 specifies equipment needed to perform the minimum detection limit testing required by paragraph 6.1.2 and the operating envelopes required in Section 8. For clarity we recommend paragraph 6.2 be modified to be clear on where these requirements apply. **We recommend the following revised paragraph 6.2:**

> **6.2 The following items are needed for the initial performance verification of each OGI camera model configuration, as required by paragraph 6.1.2 and Section 8:**

F. Paragraph 6.2.4 calls for use of a mass flow controller or rotameter capable of controlling the methane and butane rates within a National Institute of Standards and Technology (NIST) traceable accuracy of 5% when testing a camera's detection limit or operating envelope. NIST traceability is not specified for any other instrumentation used in these demonstrations and seems unnecessary for this use. **We recommend the requirement for NIST traceability be removed.**

G. The paragraph 6.2.6 subparagraphs specify requirements for weather stations from which data will be used for the minimum detection limit testing required by paragraph 6.1.2 and the operating envelope testing in Section 8. It specifies the weather information be obtained from a weather station within 1 mile of test location and that the weather station instrumentation meets various listed specifications. In many cases, National Weather Service stations will be the basis for this data, and the testing facility will not have ready access to the instrumentation specifications at that weather station or the ability to influence that equipment. **We therefore recommend that weather data obtained from a National Weather Service Station located within 1 mile of the test location be allowed without requiring the information specified in paragraphs 6.2.6.1 through 6.2.6.5 to be collected.**

H. Paragraph 6.2.6.4 contains a typographical error. Wind direction is measures in degrees, not degrees Celsius as indicated in the draft.

9. Section 7 Camera Calibration and Maintenance

Our members report their experience with OGI cameras confirms that these cameras do not require any on-going calibration or routine maintenance. Thus, **we support Section 7 as proposed.**

10. Section 8 Initial Performance Verification and Development of the Operating Envelope

A. Paragraph 8.1 requires a record be maintained with other OGI records that each OGI camera meets the minimum detection limit requirements in paragraph 6.1.2. As indicated in Comment II.8.B, we anticipate it will be primarily the camera manufacturer's responsibility to assure the camera meets those specifications. Furthermore, many of these cameras will be used at multiple, separate facilities owned by different entities and it would be difficult and lead to a lack of cohesion for every entity that uses the camera and must maintain OGI monitoring records to have to maintain a copy of that documentation. **API therefore recommends this requirement be revised to require that the manufacturer of the OGI camera or other entity that performs the paragraph 6.1.2 evaluations be required to maintain the records showing compliance with the minimum detection limits and that such a record not be required to be kept by the camera owner or at each location where the camera is used. Further, we recommend this recordkeeping requirement be moved to paragraph 6.1, where it better fits (See Comment II.8.D).**

B. Operating Envelopes

a. As we discuss in Comment II.8.C, EPA's data shows equivalent performance is obtained by using the same methane/propane mix as used in part 60 subpart OOOOa for establishing camera minimum detection limits and operating windows as is obtained using methane and butane as proposed. Therefore, it is unnecessarily burdensome to require sources to change from a methane/propane mixture to methane and butane. **We therefore request that Appendix K allow use of either approach for setting operating envelope parameters (i.e., use methane/propane mix or use methane and butane)**.

b. As with the requirements in paragraph 6.1.2, in most cases establishing operating envelopes per the requirements of proposed paragraphs 8.2 through 8.6 can most efficiently, and with minimum methane and butane emissions, be developed by the manufacturer for each camera model configuration that could impact the camera's capabilities. Some camera configuration variations will not impact the camera capabilities and thus will not need a separate operating envelope. For instance, it usually makes no difference if a camera is hand-held, mounted on a tripod or mounted on a drone. If the mount is appropriately located to meet the maximum monitoring distance parameter of its operating window and is stationary (e.g., drone is hovering if a drone mount is in use) the same operating envelope is applicable. While there may be cases where a different operating envelope is needed for a unique monitoring situation, that will be the exception rather than the rule. In most cases, a single or a few operating envelopes will suffice for most monitoring. The key, which is addressed in Section 9 of the proposal, is assuring all equipment components being monitored are within an established operating envelope when they are monitored. **We, therefore, recommend that it be made clear in paragraph 8.3 that operating envelopes may be developed by the manufacturer <u>or</u> by others for each camera model and that separate operating envelopes are only required for camera configurations that impact the camera's ability to reliably locate leaks.**

c. **API also recommends paragraph 8.6 be revised to require that the entity that develops an operating envelope for an OGI camera model or configuration be required to maintain the records supporting that operating envelope and that not everyone that has to maintain OGI monitoring results must have those records, as the proposed paragraph 8.6 language would seem to require.** Since the users of an OGI camera need to know what operating envelopes are applicable, and the parameters for those operating envelopes**, we also recommend that the OGI camera owner or user maintain a record of the operating envelope parameters that apply for each configuration of their camera that they use.** Again, this needs to be the camera users or owners' responsibility, since many of these cameras will be used at multiple locations owned or operated by many different entities and the camera owner may not even be a facility owner or operator (e.g., a monitoring contractor).

d. Finally, it would be a clarification if the wording of paragraphs 8.3 through 8.6 be revised to indicate there may be multiple operating envelopes for a particular camera configuration. **We suggest a few specific wording revisions in the Appendix K redline included in this submission**.

11. Section 9 Conducting the Monitoring Survey

A. General

a. Throughout Section 9 of the proposal the monitoring plan requirements are stated as requirements for each site. However, much of the information is not site specific (e.g., procedure for assuring operating envelope conditions are met, procedures for documenting monitoring surveys). Most of those procedures are generic for a particular camera and monitoring approach and apply to many sites, often sites with different owners. Many of the procedures in a monitoring plan will be the responsibility of the camera owner or contract monitoring firm. There is no justification for forcing every site to develop those procedures or even to have a record of the generic ones. Rather than trying to list who should be responsible for each procedure **we recommend these requirements (except for paragraph 9.7) be reworded to simply identify monitoring plan content requirements without specifying who is responsible for them.** We make specific recommendations as to maintenance of the monitoring plan records in the next comment and in our recordkeeping comments in Section 17 of these comments.

b. Section 9 of the proposal requires that each site have a monitoring plan that describes the procedures for conducting a monitoring survey. Proposed paragraph 12.2 requires the facility must maintain a record of the site monitoring plan. We comment on the specifics of recordkeeping paragraph 12.2 in Comment II.17.B, however, we believe that both the section 9 and paragraph 12.2 need to be clarified that it is not required that a copy of the plan be maintained at every site. Typically, such a plan would be developed centrally and would be available electronically as needed by the camera operators when they are monitoring that site. **We suggest the introductory sentence to section 9.0 be revised to the following.** We recommend an equivalent change in our recommended changes to paragraph 12.2.

> **9.0 A monitoring plan that describes the procedures for conducting a monitoring survey at each site must be readily available to the camera operator.**

B. **API generally supports the proposed daily initial verification checks in paragraph 9.1.** In our experience these checks assure the OGI camera is functioning properly. However, we see no value in the burden imposed by paragraph 9.1.4 that requires a video record of the camera imaging a butane lighter or other validation source. It is more than adequate to simply have confirmed that the camera sees the butane lighter image as part of confirming the entire 9.1 set of requirements were met. It is overly burdensome and unnecessary to require daily video records of that determination. Storing thousands of videos, no matter how short, is difficult and there needs to be a significant justification for any such a requirement. **API recommends paragraph 9.1.4 be deleted.**

C. Paragraph 9.3 requires a monitoring plan for each site to identify monitoring survey methodologies that ensure all regulated components are monitored. It provides only three approaches that may be used. All three approaches are extremely complex, and the burdens imposed are often not justified versus other alternatives. We comment on some of the specifics of the three approaches next (in Comment II.11.D.b), though we believe paragraph 9.3 should be replaced in its entirety.

As was found for Part 60 Subpart OOOOa sources (as described below), we believe other approaches to those proposed for assuring all components are included are available or will be identified as thousands of monitoring programs are developed and executed and as technology improves. Use of such alternatives should be encouraged where they prove more efficient**.**

Limiting survey monitoring methodologies to only three is also inconsistent with the stated intent of the current proposal[13]. On page 63165 of the current proposal, EPA states:

> The 2016 NSPS OOOOa, as originally promulgated, required that each fugitive emissions monitoring plan include a site map and a defined observation path to ensure that the OGI operator visualizes all of the components that must be monitored during each survey. The 2020 Technical Rule amended this requirement to allow the company to specify procedures that would meet this same goal of ensuring every component is monitored during each survey. While the site map and observation path are one way to achieve this, other options can also ensure monitoring, such as an inventory or narrative of the location of each fugitive emissions component. The EPA stated in the 2020 Technical Rule that ‘‘these company-defined procedures are consistent with other requirements for procedures in the monitoring plan, such as the requirement for procedures for determining the maximum viewing distance and maintaining this viewing distance during a survey.’’ 85 FR 57416 (September 15, 2020). Because the same monitoring device is used to monitor both methane and VOC emissions, the same company-defined procedures for ensuring each component is monitored are appropriate. Therefore, <u>the EPA is proposing to similarly amend the monitoring plan requirements for methane and for compressor stations to allow company procedures in lieu of a sitemap and an observation path.</u> [Underline emphasis added.]

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[13] Ibid.

For these reasons, **we request language based on Part 60 Subpart OOOOa §60.5397a(d)(1)[14] be substituted for the proposed paragraph 9.3. That language we recommend is as follows:**

> **Your plan must include procedures to ensure that all equipment leak components are monitored. Example procedures include, but are not limited to, a sitemap with an observation path or GPS coordinates, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.**

D. Should the proposed paragraph 9.3 not be replaced with the language from Part 60 Subpart OOOOa or an equivalent, we have the following comments on the proposed paragraph 9.3 language.

a. The proposed three approaches are clearly intended for use at larger operations where many monitoring locations are needed and there is a large infrastructure and significant resources to allow marking monitoring locations, mapping routes and maintaining this information. Many locations subject to the current rulemaking are smaller facilities or portions of a facility (e.g., a flow meter station or a tankfield pump station) where monitoring will require one pair of observations (two views of the components) or at the most a few observations. It is unnecessary and overly burdensome to have to manage repetitive route maps, to place and maintain monitoring location markers or even identify GPS coordinates in such situations. Thus, if section 9.3 is not replaced, **we recommend an additional option be added that would apply to facilities where less than 25 monitoring observations are needed to monitor all components regulated by a referencing subpart or permit.** The term "monitoring observation" refers to each pair of camera locations[15] used to visualize a particular collection of equipment leak components (e.g., a piping manifold, a meter station). Under that option, the monitoring plan would allow for a description of the approach that will be used (e.g., monitor all components from two views at least 90 degrees apart) and a list of the facilities or facility locations to which this option applies.

b. For the reasons discussed in Comment II.1.C, **we recommend the word "site" in paragraph 9.3 (if maintained) be removed. We suggest the paragraph start with "Conduct monitoring using …"**

c. **We also recommend the wording of paragraph 9.3 sentence two, if maintained, be clarified to indicate that a mix of the options is allowed if all components subject to OGI monitoring under the referencing subpart or permit are monitored.** As proposed, that sentence requires the use of the same option for an entire facility. For larger facilities and facilities with a mix of densely located components and remote collections of components, use of a mix of the options may be most efficient.

d. **In paragraph 9.3 (if maintained), we also recommend the last sentence be clarified to indicate that a component database is not required.**

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[14] §60.5397a(d)(1) states, "(1) If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components."

[15] Typically, at least two different views of potential leak sources are used for OGI monitoring.

e. Given the massive number of route maps, GPS coordinates and site lists that must be recorded and maintained if this provision is not replaced, **it is critical that it be clarified that this information may be in electronic form (e.g., databases, spreadsheets) and not "included as part of the monitoring plan" as apparently required by the draft language.**

E. Paragraph 9.4 and Table 14-1 specify minimum dwell times for observations.

a. **API requests EPA explain the basis for the dwell time requirements in the formal proposal of Appendix K (i.e., the Table 14-1 entries)**, so we can provide scientifically valid comments.

b. API believes that setting prescriptive dwell times is unnecessary and introduces inefficiencies and wasteful burdens. An experienced camera operator will determine dwell time based on the circumstances – some views may require an extended dwell time and other views may need shorter dwell time. **Dwell time should be an element of operator training and auditing, but not specified in Appendix K.** Dwell time is already included in paragraph 10.2.1.5 training requirements, in monitoring plan requirements and dwell time issues would become readily apparent in the final field training test and during performance audits and other quality control activities as required by paragraph 11.1. In the work of Zimmerle[16], et. al. dwell times were not identified on a per component basis. However, they did report the range of times operators took to complete surveys of three different typical upstream installations, where leaks were artificially introduced. They reported the range of monitoring times as follows.

Test Site	Monitoring Time (min)
1	3-52 (mean 19)
2	1-89 (mean 18)
3	9-108 (mean 39)

With that wide range of monitoring times, it is impossible to identify minimum dwell times that do not introduce inefficiency. Unnecessarily long dwell times result in inefficient emission reductions and take time and resources away from other compliance activities with greater environmental benefits. Zimmerle's work clearly identifies that experienced operators adjust the dwell time of an individual observation to account for environmental considerations (e.g., background) and for the type of equipment and process conditions and the likelihood of leaks. It is the ability to make these adjustments that makes the monitoring process efficient. If dwell times are not flexible, efficiency is lost, since extended time is spent looking at the many components that are not leaking or even likely to leak. Zimmerle also reported that while the number of smaller leaks identified increased with increased monitoring times, identification of larger leaks was not significantly impacted, so the mass of emissions identified was not overly sensitive to the monitoring time.

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[16] Ibid.

Specifying a dwell time discourages a camera operator from adjusting for prevailing conditions. Once the specified dwell time is reached there is no reason for an operator to spend additional time, even if the situation requires it.

F. Paragraph 9.5 requires that the monitoring plan address camera operator fatigue. It includes specific requirements to address this concern. Imposing specific ergonomic requirements such as proposed in this paragraph is outside the scope of an EPA method. Furthermore, the approach must be tailored to the situation. For instance, under this rulemaking most monitoring will be in short bursts with travel time between monitoring locations. Nothing specific is needed in these situations to prevent operator fatigue. In more densely populated situations relief may be needed, but the times for breaks need to be matched to the situation. For instance, arbitrarily requiring a break 5 minutes before lunch or quitting time makes no sense. Similarly, stopping a monitoring round that takes 23 minutes to complete for a break at twenty minutes (as specified in the proposal) is equally nonsensical. Additionally, 20 minutes may be too long between breaks in some situations. For instance, if the camera operator had to climb a hundred-foot tower to perform monitoring or monitor in particularly hot situations.

We do not believe there is a generic approach that would not significantly interfere with the efficient execution of this program and **we, therefore, recommend that all but the first sentence of proposed paragraph 9.5 be deleted**.

G. Paragraph 9.6 requirements apply to a "monitoring survey," but that is an undefined and ambiguous term and the requirements do not really fit since, depending on the situation, single site or even a single process unit can take anywhere from less than an hour to many days to complete. Furthermore, we see no value for requiring weather data when monitoring moves from one process unit to another at the same location or at the end of the day. Even where there are large process units, weather does not change significantly because of location changes within a facility and end of day weather information is of no use in assuring operating envelope requirements are being met, since monitoring has concluded for the day.

We suggest paragraphs 9.6.1 and 9.6.2 be replaced with the following to address this variability

> **9.6.1 For each monitoring day or change in facility, record the date, approximate start and stop times and the name of facility where the monitoring is performed.**
>
> **9.6.2 At the start of each monitoring day or a change in facility, record the weather conditions, including ambient temperature, wind speed, relative humidity,and sky conditions.**

H. Leaks

a. Paragraph 9.7 specifies documentation requirements for leaks found (video clip) and clarifies that no video record is required unless a leak is found. **API strongly supports the important clarification that individual records are not required unless a leak is identified.** Obtaining and maintaining video records is a major burden and is only justified where there is a reason, such as where a leak has been identified and a video clip or digital picture will aid in identifying the location of the leak for repair personnel.

b. Paragraph 9.7.1 requires that if a leak is identified, a video clip be taken, and the leak tagged for repair. The final sentence of the paragraph suggests the video clip is needed to allow the operator to find the leak. Since it is required that the leak be tagged, it does not seem there would be a need for a video or even a still picture to help find the leak. As indicated in the subpart OOOOa quote below, that subpart only requires tagging or an image, not both. No justification for requiring both is provided in the record.

Furthermore, there are situations where immediate repair or tagging of a leak can impose a potential safety problem and thus the absolute requirement to tag all leaks is infeasible. Safety issues occur, for instance, if the leak is in an extremely hot piece of equipment (e.g., in a furnace process outlet line), where there is no immediate safe access available (e.g., in a pipe rack, on the side of a tower), or where toxics such as hydrogen sulfide is or may be present. In these cases, a video or a digital picture could be helpful in identifying the leak location and the burdens associated with requiring such a record are justified. As we have previously discussed, any video record requirement adds burden and can be difficult to reliably meet. A digital picture, as opposed to a video, has the advantage of being much easier to store and can better show reference points that help identify the leak location when compared to video. Paragraph 60.5397a(h)(4)(ii) of part 60 subpart OOOOa requires a digital picture of leaks that are not immediately repaired or tagged, and that approach has been in successful use since September of 2015. Paragraph 60.5397a(h)(4)(ii) states:

> For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component, or the component must be tagged during the monitoring survey when the fugitives were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

Thus, **we request that paragraph 9.7.1 be revised to parallel the part 60 subpart OOOOa approach, allowing either a video or a digital picture and only imposing that requirement where a leak is not immediately repaired or tagged and that only a written record of the leak information be required otherwise.**

I. Paragraph 9.7.3 requires a 5-minute per day quality assurance video for each camera operator. The paragraph specifies that the video must document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration. It is unclear how such a video clip would show compliance with that list of items. For instance, dwell times, angles, distances, backgrounds will vary for every monitoring occurrence, since they depend on the equipment being monitored, the location of the camera relative to the component locations, the background and the weather. A video does not show whether those parameters are being met. A video does not show whether all operating envelope criteria are being met, even for the situation being viewed. Furthermore, video of camera operators who know they are being videoed is unlikely to be representative. The required quarterly (or as we recommend annual) performance audits, proper training, the daily equipment startup checks and the quality assurance requirements in paragraph 11.1 provide all the appropriate quality assurance much more effectively and efficiently than this proposed video requirement. Furthermore, creating extensive video records that are difficult to reliably store, provide no useful information, and are unlikely to ever be reviewed, imposes a large and overly burdensome mandate.

We are also concerned that EPA underestimates the burden of storing video files, specifically storing the 5-minute per camera operator per day videos required in paragraph 9.7.3. There are actual examples of data storage issues associated with the requirement in MACT CC (63.670(h)(2)), which requires recordkeeping of photos taken of a flare every 15 seconds (or 2,102,400 images per year per flare). For at least one of our member companies operating several refineries, the flare images are *not* stored on the Cloud. Rather, they are saved locally on a server for several reasons, primarily for security. Refineries often have very tight Information Technology (IT) security systems because of the nature of the industry. Additionally, some member companies have experienced a loss of some of the photos because of power outages or other technical issues associated with handling the sheer volume of images. The flare images add up quickly, and the videos required by paragraph 9.7.3 will as well. For comparison, a high-definition video is 60 frames per second. Assuming 5 such videos per day for 250 days per year for a refinery then represents 22,000,000 images. The burden of saving these videos on the slight chance someone may want to review one is not justified, since, as discussed above, we do not see them providing any compliance assurance value.

Paragraph 9.7.3 and the corresponding entry in the table in paragraph 11.3 should be deleted.

12. Paragraph 10.2 Initial OGI Camera Operator Training

Paragraph 10.2.1 addresses initial “classroom” training of OGI camera operator trainees. As discussed in Comment II.1.F, it needs to be clarified throughout Appendix K that this can be computer-based training and does not have to be in-person classroom training.

Paragraph 10.2.2 addresses the required field training. It calls for a minimum of 1) 10 site surveys where the trainee is observing a senior OGI operator, 2) 40 site surveys where monitoring is performed side-by-side with a senior OGI operator, 3) 50 site surveys where a senior OGI operator observes the trainee performing monitoring and 4) a final survey where a senior OGI operator performs a follow-up survey that demonstrates the trainee did not miss any persistent leaks. There are many issues with these requirements as follows.

A. Paragraph 10.1 calls for a training plan. It includes a sentence saying, “If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement.” **API recommends this sentence be deleted.** Any company contracting for OGI monitoring services has a responsibility to assure that those services meet any applicable requirements. There is no reason a training plan is any more critical than any of the other requirements of Appendix K. Nor is it clear how individual facilities would "ensure" compliance with the training plan requirements or why each facility would have that responsibility if the monitoring contract involved many facilities. Imposing an unclear burden on every facility that does OGI monitoring using Appendix K aggregates to a large and unnecessary burden.

B. As discussed in Comment II.1.C, site is an imprecise term and could require monitoring for minutes at a location with only a few potential leak components or could require monitoring for months at a location with hundreds of thousands of potential leak components. Thus, **we recommend the word "site" be deleted from these paragraphs and these training requirements should be based on monitoring hours as discussed below.**

C. If we assume a reasonable training OGI survey as roughly 20 minutes of monitoring (EPA's suggested monitoring duration without a break in proposed paragraph 9.5), the proposal will require over 34 hours of actual field monitoring training for the trainee and over 17 hours of one-on-one senior OGI operator monitoring time, assuming as discussed below the required observational items can be done in groups. Obviously, much more time would be required if "survey" is left undefined and thus involved more than 20 minutes of monitoring. Considering set-up, breaks, lunch, equipment relocation, etc. this will require well over a week of trainee time and half a week of senior operator time (per trainee).

In our experience, 34 hours of field monitoring training is unnecessary to assure well-trained operators. In fact, Texas has concluded only 24 hours of total initial training is necessary[17]. Based on that experience, the need to train large numbers of OGI camera operators initially and the likely shortage of senior OGI camera operators, **we recommend 1) field monitoring training be limited as discussed below, 2) field monitoring training require monitoring surveys of approximately 20-minutes each and 3) that it be clarified that the observational portions of the training do not have to be one-on-one**. We amplify on these recommendations in the following comments (II.12.D and E). In combination with the initial classroom or computer-based training, these recommendations would provide more than the 24-hour minimum required by Texas.

D. Paragraph 10.2.2 requires 10 surveys where the trainee observes a senior operator, 40 surveys side-by-side with a senior OGI operator and 50 surveys with a senior operator overseeing the trainee. In our experience, this is excessive, particularly the amount of side-by-side surveying. Nor as discussed below and elsewhere, will there be enough senior OGI operators to perform these functions if the requirements for reaching senior operator status are unchanged. We believe side-by-side monitoring can be done with operators meeting our suggested revised senior OGI camera operator definition with no loss in quality versus senior operators meeting the proposed definition. It is also important that the

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[17] §115.358(h)(1) of Title 30 of the Texas Administrative Code requires "Operator training. Any person that performs the alternative work practice in this section shall comply with the following minimum training requirements.

(1) The operator of the optical gas imaging instrument shall receive a minimum of 24 hours of initial training on the specific make and model of optical gas imaging instrument before using the instrument for the purposes of the alternative work practice.

revised language be clear that the observational training does not have to be one-to-one (see our suggestions in the Appendix K redline attached to these comments). Thus, **we recommend these requirements be revised to 10 20-minute monitoring surveys where a group of trainees observes a senior OGI camera operator, 50 20-minute monitoring surveys where a senior operator oversees a group of trainees and 5 20-minute monitoring surveys side-by-side with a qualified operator.** The proposed final survey test in proposed paragraph 10.2.2.4 (modified as discussed below) would complete the training. This would provide a total of approximately 23 hours of field experience for each trainee prior to their starting to perform monitoring surveys.

E. Final Field Training Test

a. Paragraph 10.2.2.4 requires a final monitoring test where the trainee conducts an OGI survey, and a senior OGI camera operator follows behind with a second camera to confirm the trainee's survey results. Consistent with our recommendation for performance audits below, **we recommend this final test be of 1-hour duration (e.g., 3 20-minute periods) to assure a sizable number of components are monitored.**

b. The criterion for passing this final test is "The trainee must achieve zero missed persistent leaks relative to the senior OGI camera operator …" We believe the criterion of zero missed persistent leaks is unreasonable and should be revised. First, even if the follow-up survey is performed immediately after the trainee's survey, there can be changes in leak rates, interferences, etc. that occur and can cause a marginal leak to be observed in one survey and not the other. Second, a leak may occur continually through a dwell period and still not occur at another time. Thus, it is quite possible in the real world that a leak can be observed in one survey and not occur in another survey even if the other survey is just a few minutes earlier or later. These differences can occur for either survey. In the real world, it is just as likely the trainee will observe "persistent" leaks that the qualified operator does not. EPA has acknowledged this potential issue for marginal leaks even in carefully controlled situations by establishing a 75% criterion (3 out of 4) when establishing operating envelopes for an OGI camera.[18] As proposed, paragraph 10.2.2.4 also presumes the senior operator monitoring always observes more leaks than the trainee observes. That is unreasonable and the passing criteria must allow for either situation. For these reasons, **we recommend that the criterion for passing the final test be changed to at least 90% agreement or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

c. Paragraph 10.2 is silent as to what is required if an OGI operator trainee fails the final test required by paragraph 10.2.2.4. **API recommends that if 90% agreement is not achieved, the senior operator should work with the trainee on the reasons for the failure and then the test should be repeated.** In the case of a second failure, the trainee should be required to go through the refresher level of training prescribed in paragraph 10.3 before retaking thew final test. A one and done failure construct creates arbitrary barriers to developing a qualified workforce.

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[18] See paragraph 8.5.3 of the proposal.

13. Paragraph 10.3 Refresher training

A. Paragraph 10.3 requires annual refresher training for OGI operators. In our experience annual refresher training is unnecessary considering the ongoing quality assurance requirements, and the typical amount of oversight that occurs. Even in the TSD, it is recognized that refresher training is not always needed. For instance, it is stated on page 115 that "If OGI technicians are regularly sent out to the field to perform surveys, then re-validating their performance may not be necessary, but could also be as simple as having a superior repeat a survey and report on the established technician's performance." **We recommend the refresher training be on a three-year interval.**

B. There are many OGI monitoring programs already underway and thus there are some experienced camera operators already in place. It would be unnecessarily burdensome for them to have to go through the entire initial training program when they first must meet Appendix K requirements. They would only need to understand the specific requirements of this Appendix. Thus, **we recommend that an OGI camera operator with at least 24 hours of OGI monitoring experience in the previous 12 months, but no previous Appendix K experience, only be required to go through the refresher level of training rather than the full initial training and then pass the field training final test in paragraph 10.2.2.4.**

14. Paragraph 10.4 Performance Audits

A. Paragraph 10.4 requires quarterly performance audits. Our experience suggests that formal quarterly audits of camera operators are excessive. We note that other similar work practice programs, such as the Method 21 LDAR monitoring program has been successfully in service for more than 40 years without a similar audit requirement. Considering the requirements for an on-going quality control program in proposed paragraph 11.1, annual performance audits are certainly adequate. **We recommend changing this requirement to annual audits**.

Besides reducing burdens and freeing camera operators for actual monitoring activities, this change in audit frequency has the added benefit of reducing the demand on senior OGI camera operator time, thereby allowing more time for senior operators to do monitoring and training.

B. Since senior OGI camera operators will carry out any required performance audits, they will automatically frequently review monitoring requirements and have an opportunity to identify and correct any issues of their own. Such issues would be apparent as they compare results if a comparative monitoring option is used and when reviewing, either in person or via video the auditee. Thus, **API recommends senior OGI camera operators not be required to undergo performance audits.**

C. Paragraph 10.4.1 outlines a performance audit option using comparative monitoring and paragraph 10.4.2 outlines a performance audit option using video review. We comment on the specifics of those approaches in our next comment (Comment II.14.D). We support providing alternative audit approaches, since there will be many variants in monitoring organizations, monitoring schedules, senior OGI camera operator availability, and facilities, but believe there are more than two alternatives to evaluating the performance of a camera operator. Therefore, **we recommend that the performance audit methodologies that will be used be required to be included in the monitoring plan as already implied in proposed paragraph 11.1 and that the approaches in paragraphs 10.4.1 and 10.4.2 only be cited as examples.**

Alternative approaches include visual observation by a senior OGI camera operator (as opposed to their reviewing a video) or observation by a monitoring supervisor or review of results from monitoring at a test facility, among others.

D. Performance Audit Procedures

a. Paragraphs 10.4.1.1 and 10.4.2.1 require audits of at least 4-hours with no persistent leaks identified by the auditor that were missed by the auditee. Four hours is an excessively lengthy period and is not needed to assess if an auditee is monitoring correctly. One-hour is more than adequate to determine if the auditee is following procedures and can identify leaks. Nor is a 4-hour requirement it a reasonable use of resources, tying up an OGI camera operator and an auditor for more than a day per audit (4-hours for the trainee monitoring and 4 hours for the follow-up senior OGI operator survey) and for video audits a third person (taking the video) for half a day. **We recommend the 4-hour requirement be changed to require audits of 1-hour total duration (i.e., 3 20-minute periods) and, as discussed in Comment II.14.A, these audits only be required annually.**

b. Paragraph 10.4.2 provides a performance audit procedure wherein a senior OGI camera operator observes the auditee by reviewing a video of that auditee performing monitoring. While that approach is useful where senior operators are not readily available, in many cases it would be easier for the senior operator to simply observe the auditee by following them around. This also eliminates the issues associated with needing an additional (i.e., third) person to take the video and of storing the video. **Thus, if this requirement is maintained, we recommend it also allow for a senior operator to simply observe the auditee and not have to record a video.**

c. For all the reasons presented in Comment II.12.E.b, **we also recommend that the criterion for passing the audit be changed to at least 90% agreement of the number of persistent leaks found or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

d. **We also request EPA make clear that these audits may be performed by the OGI camera operator employer or a site owner or operator and there is no requirement for additional audits as the camera operator moves from one site to another or from employer to employer.**

e. There is a typographical error in that paragraph 10.4.2.2 is labelled as 10.4.2.3 in the draft Appendix K.

f. Paragraphs 10.4.1.2 and 10.4.2.2 specify retraining requirements for an operator that fails the audit criterion. The retraining requires a minimum of 1) 10 site surveys where the trainee is observing a senior OGI operator, 2) 5 site surveys where monitoring is performed side-by-side with a senior OGI operator, 3) 10 site surveys where a senior OGI observes the monitoring and 4) a final survey where a senior OGI operator performs a follow-up survey that demonstrates the operator in training did not miss any persistent leaks. First, as discussed in Comment II.1.C **we recommend the word “site” be deleted**

from these paragraphs and the monitoring requirements be expressed on a time basis. Second, we believe the retraining proposed is excessive and overly burdensome. Failures to observe a leak or to follow some aspects of the monitoring procedure are situation specific. General retraining dilutes the focus on the real problem(s) and uses up precious monitoring time and senior resources on issues that are not a problem. Therefore, we believe it is impossible to specify a retraining paradigm that is generic and resource efficient. Rather, **we believe the requirement should be to specify that retraining is required to address monitoring aspects observed to be an issue during the audit and that the auditee must then pass a new comparative audit by achieving at least 90% agreement on the number of persistent leaks or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

15. Paragraph 10.5 Returning Operators

A. This paragraph states, "If an OGI camera operator has not conducted a monitoring survey in over 12 months, then they must repeat the initial training requirements in Section 10.2." This is excessive for an experienced operator who has, for example, been temporarily in another job or out due to an extended sickness. Rather, **we recommend the returning operator be only required to take refresher training and to pass a performance audit. Furthermore, for clarity, we recommend this requirement be integrated into paragraph 10.3 on refresher training.**

16. Section 11 Quality Assurance and Quality Control

A. Consistent with our recommendation in Comment II.11.J to delete Paragraph 9.7.3, **the second sentence of paragraph 11.2 should be deleted.**

B. We have commented individually on the QA/QC requirements proposed throughout. **Paragraph 11.3 summarizes those requirements and will need to be updated to match the final version of the Appendix.** We have included recommended revisions in the redline version of Appendix K that we are submitting with these comments.

Additionally, some of the wording in the frequency column of that table is unclear as to who is responsible and how often and on what basis the QA/QC activity is required. We have suggested improved wording and addition of specific references to the paragraph containing the requirement in the redline version of Appendix K that we are submitting with these comments.

17. Section 12 Recordkeeping

A. As indicated in the following specific comments, "facility" is the wrong basis for requiring most records. Many of the required records will be developed by the camera manufacturer. Others should be housed in owning or operating company central repositories because it is more efficient and because some sites potentially subject to these requirements are not continuously staffed and have no onsite recordkeeping facilities. Training and other operator records should be handled by the camera operator's employer, often not the owner/operator of any facility being monitored. Nor would it be manageable or sensible to require copies of these various records to be made for each of the facilities that will be subject to monitoring. **Thus, as suggested more specifically below, we recommend the word "facility" be deleted from this section and the appropriate entity (e.g., camera owner, facility owner or operator, camera operator employer) be substituted or no specific entity be identified as having to maintain the record.** Consistent with this change, **the general recordkeeping requirement in paragraph 12.1 should be generalized to "Records required by this Appendix must be kept for a period of five years, unless otherwise specified in an applicable subpart."**

B. Paragraph 12.2 says, "The facility must maintain the following records in a manner that is easily accessible to all OGI camera operators:" However, except for paragraph 12.2.1 (the site monitoring plan) and 12.2.4 (operating envelope limits) the other listed records are associated with the camera, and many cameras will be used at multiple facilities and may not be owned by the facility or even the facility owner. In fact, it can be anticipated that many cameras will be owned by a monitoring company. Even in the case of the site monitoring plan, as we discussed in Comment II.11.A, much of the content of that plan will be the responsibility of the camera owner. While a facility owner or operator will have significant input relative to monitoring routes and safety issues, the camera owner or monitoring contractor is the appropriate owner of this plan it would be their responsibility to see that their camera operators have ready access to the plan, not the responsibility of the facility owner unless the monitoring personnel are in-house. **Thus, "facility" should be deleted from the paragraph 12.2 wording, and it should be rephrased to say, "The following records must be maintained, as applicable" and a sentence added to require that operating envelope limits and applicable site monitoring plans be readily accessible to camera operator.**

C. Paragraphs 12.3 requires records of data supporting development of the operating envelope. We anticipate most, though not all, operating envelope development will be done by the camera manufacturer and thus **paragraph 12.3 should require operating envelope supporting data to be maintained by the developer of the operating envelope.**

D. Paragraph 12.4 contains requirements applicable to camera operators. These records are the purview of the operator's employer and not , in most cases, individual facilities or even operating companies. **Paragraph 12.4 should be clarified to require these records to be maintained by the camera operator's employer or facility owner or operator as applicable.**

E. Paragraph 12.4.3 appears to require records of operator training activities, but starts by requiring "The number and date of all surveys performed …" Records of actual monitoring surveys need to be maintained by the owner or operator of the site monitored and are covered by paragraph 12.5. Thus, this introductory phrase in paragraph 12.4.3 needs to be limited to surveys associated with training. If some of those training surveys are performed to locate leaks, records will need to be maintained with the training records required by paragraph 12.4.3 and, also, with monitoring records as required by paragraph 12.5. **We therefore recommend the introductory phase in paragraph 12.4.3 be revised to "The number and date of all training surveys performed …"**

F. Paragraph 12.5 deals with monitoring records and requires that the listed records be available to the technicians' executing repairs. Yet, most items are not associated with repairs or locating the leak and it is overly burdensome to require that they be made available, particularly if the monitoring is not being performed by an employee of the site being monitored. **Therefore, we recommend only proposed paragraph 12.5.6 be required to be available to the repair technicians**.

Attachment B

Suggested Redlines to Prepublication Draft Appendix K

Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging

[API recommended changes shown in redline mode]

1.0 Scope and Application

1.1 Analytes.

Analytes	CAS No.
Volatile Organic Compounds (VOCs)	No CAS number assigned.
Methane	74-82-8
Ethane	74-84-0

1.1.1 This protocol is applicable to the detection of VOCs, including hazardous air pollutants (HAPs),and hydrocarbons, such as methane and ethane.

1.2 Scope. This protocol covers surveys of process equipment using Optical Gas Imaging (OGI) cameras in oil and gas upstream and downstream sectors (from production to refining to distribution). Thespecific component focus for the surveys is determined by the applicable subpart, and can include, but is not limited to, valves, flanges, connectors, pumps, compressors, open-ended lines, pressure relief devices,and seal systems.

1.3 Applicability. This protocol is applicable to equipment leak components at facilities ~~all facility types from the upstream and downstream oil and gas sectors and may apply to well heads, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities~~ when referenced by an applicable subpart. ~~This protocol is not applicable to chemical plants or other facility types outside of the oil and gasupstream and downstream sectors.~~ This protocol is intended to help determine the presence and location of leaks and is not currently applicable for use in direct emission rate measurements from sources.

2.0 Summary

2.1 A ~~hand-held,~~ field portable infrared (IR) camera capable of imaging the target gas species is employed to survey process equipment and locate fugitive or leaking gas emissions. By restricting the amount of incoming thermal radiation to a small bandwidth corresponding to a region of interaction for the gas species of interest, the camera provides an image of an invisible gas to the camera operator. The camera type and manufacturer are not stated in this protocol, but the camera used must meet the specifications and performance criteria presented in Section 6. The keys to becoming proficient and maintaining leak detection proficiency using OGI cameras are proper camera operator training with sufficient field experience and conducting OGI surveys frequently throughout the year.

3.0 Definitions

Ambient air temperature means the air temperature in the general location where the OGI survey isbeing performed.

Applicable subpart means a subpart in 40 CFR part 60, 61, 63, or 65 that requires the monitoring of regulated equipment for fugitive emissions or leaks, for which this protocol is referenced.

Camera Configuration means different ways of setting up an OGI camera that affect the detection capability. Examples of camera configurations that can be changed include the operating mode (*e.g.,* standard versus high sensitivity or enhanced), the lens, the portability (*e.g.,* handheld versus tripod or drone mounted), and the viewer (*e.g.,* OGI camera screen versus an external device like a tablet).

Certified Thermographer, for the purposes of this Appendix, means a thermographer who has successfully completed the requirements for a Level 2 or higher thermography certificate compliant with ASNT-TC-1A or ISO 18436-7.

Delta temperature (delta-T or ΔT) means the difference in temperature between the emitted process gas temperature and the surrounding background temperature. It is an acceptable practice in the field to assume that the emitted process gas temperature is equal to the ambient air temperature.

Dwell time means the time required to survey a manageable subsection of a scene in order to provide adequate probability of leak detection. The dwell time is the active time the operator is looking for potential leaks and does not begin until the scene is in focus and steady.

Fugitive emission or leak means any emissions observed using ~~OGI~~optical gas imaging from any equipment component identified in the referencing subpart or permit as being subject to monitoring using this Appendix (Appendix K).

Imaging is the process of producing a visual representation of emissions that may otherwise be invisible to the naked eye.

Operating envelope means the range of conditions (*i.e.,* wind speed, delta-T, viewing distance) within which a survey must be conducted to achieve the quality objective.

Optical gas imaging camera means any ~~hand-held,~~ field portable instrumentation that makes visible emissions that may otherwise be invisible to the naked eye.

Persistent leak is any leak that is not intermittent in nature.

~~*Repair* means that a component is adjusted, or otherwise altered, to eliminate a leak.~~

Response factor means the OGI camera's response to a compound of interest relative to a reference compound at a concentration path-length of 10,000 part per million-meter. ~~Response factors can be obtained from peer reviewed articles or may be developed according to procedures approved by the Administrator.~~

Senior OGI camera operator is a camera operator who has performed at least 100 hours of OGI monitoring (excluding their own initial and refresher training time) in the previous 12-months and has either 1) successfully completed the initial and field training specified in Section 10 of this Appendix and has completed any required refresher training or 2) is a certified thermographer. ~~has conducted OGI surveys at a minimum of500 sites over the entirety of their career, including at least 20 sites in the past 12 months, and has completed or developed the classroom camera operator training as defined in Section 10.2.1.~~ Previous 12-months means the 365-calender days prior to the day of the activity that requires a senior OGI camera operator.

4.0 Interferences

4.1 Interferences from atmospheric conditions can impact the operator's ability to detect gas leaks. Itis recommended that conditions involving steam, fog, mist, rain, solar glint, high particulate matter concentrations, and extremely hot backgrounds are avoided for a survey of acceptable quality.

5.0 Safety

5.1 Site Hazards. Prior to applying this protocol in the field, the potential hazards at the survey site should be considered; advance coordination with the site is critical to understand the conditions and applicable safety policies. This protocol does not address all of the safety concerns associated with its use. ~~It is the responsibility~~

~~of the user of this protocol to establish appropriate health and safety practices and determine the applicability of regulatory limitations prior to implementing this protocol.~~

5.2 Hazardous Pollutants. Several of the compounds encountered over the course of this protocol maybe irritating or corrosive to tissues (*e.g.*, heptane) or may be toxic (*e.g.*, benzene, methyl alcohol, hydrogen sulfide). Nearly all are fire hazards. Chemical compounds in gaseous emissions should be determined from process knowledge of the source. Appropriate precautions can be found in reference documents, such as reference 13.1.

6.0 Equipment and Supplies

6.1 An OGI camera meeting the following specifications is required:

6.1.1 The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition.

6.1.2 Your OGI camera must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60 grams per hour (g/hr.) from a quarter inch diameter orifice. Alternatively, t~~T~~he OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 ~~grams per hour (~~g/hr.~~)~~ and butane emissions of 18.5 g/hr. at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less.

6.1.3 Documents demonstrating compliance with paragraphs 6.1.1 and 6.1.2 must be retained with other OGI records by the owner or operator or testing organization, as applicable.

6.2 The following items are needed for the initial performance verification of ~~the~~ each OGI camera model configuration, as required by paragraph 6.1.2 and Section 8:

6.2.1 Methane test gas, chemically pure grade (99.5%) or higher and Butane test gas, chemically pure grade (99%) or higher, or~~.~~

6.2.2 ~~Butane test gas, chemically pure grade (99%) or higher.~~A gas that is half methane, half propane at a concentration of 10,000 ppm.

6.2.3 Release orifice, ¼ inch in diameter.

6.2.4 Mass flow controller or rotameter, capable of controlling the gas emission rate within ~~NIST traceable~~ an accuracy of 5 percent.

6.2.5 An industrial fan, capable of adjusting the sustained nominal wind speeds at regular intervals up to 15 m/s, with the ability to maintain a set speed within 20 percent of the target wind speed.

6.2.6 A National Weather Service Station located within 1 mile of the test location. Alternatively, a meteorological station within 1 mile of the location of the testing capable of providing representative data and meeting the following minimum specifications at least once every hour:

6.2.6.1 Ambient temperature readings accurate to at least 0.5 °C, with a resolution of 0.1 °C or less, and a minimum range of -20 to 70 °C.

6.2.6.2 Ambient pressure readings accurate to at least 1.5 millibar (mbar), with a resolution of 0.1 mbar or less, and a minimum range of 700 to 1100 mbar.

6.2.6.3 Wind speed readings accurate to at least 0.1 m/s, with a resolution of 0.1 m/s or less, and a minimum range of 0.1 to 20 m/s.

6.2.6.4 Wind direction readings accurate to at least 5 ~~°C~~degrees, with a resolution of 1 ~~°C~~degree or less.

6.2.6.5 Relative humidity readings accurate to at least 2 percent, with a resolution of 0.1 percent or less, and a minimum range of 10 to 90 percent noncondensing.

6.2.7 A temperature-controlled background large enough for viewing the emissions plume and capable of maintaining a uniform temperature. Uniform is defined as all points on the background deviating no more than 1 °C from the average temperature of the background.

6.2.8 T-type probe thermocouple and readout, accurate to at 1 °C, for measuring the test gas at the point of release.

6.2.9 T-type surface skin thermocouple and readout, accurate to at 1 °C, for measuring the background immediately behind the test gas.

6.2.10 Device to measure the distance between the OGI camera and the release point (e.g., tape measure, laser measurement tool), accurate to at least 2 centimeters (cm), with a resolution of at least 1 cm.

7.0 Camera Calibration and Maintenance

The camera does not require routine calibration for purposes of gas leak detection but may require calibration if it is used for thermography (such as with ΔT determination features).

8.0 Initial Performance Verification and Development of the Operating Envelope

8.1 Determine that the OGI camera meets the specification in Section 6.1. ~~A document demonstrating compliance with this requirement must be retained with other OGI records.~~

8.2 Field conditions such as the viewing distance to the component to be monitored, wind speed, ambient air temperature, and the background temperature all have the potential to impact the ability of the OGI camera operator to detect the leak. It is important that the OGI camera has been tested under the full range of expected field conditions in which the OGI camera will be used.

8.3 ~~An o~~Operating envelopes must be established for field use of the OGI camera. ~~The~~ An operating envelope must be confirmed for all potential configurations that impact the camera's capabilities, such as high sensitivity modes, available lenses, and, in some cases, handheld versus tripod or drone mounted. ~~Conversely, separate operating envelopes may be developed for different configurations.~~ If, in addition to or in lieu of the display on the camera itself, an external device (*e.g.*, laptop, tablet) is intended to be used to visualize the leak in the field, the operating envelope must be developed while using the external device. If the external device will not be used at all times, use of the external device is considered a separate configuration, and ~~the~~ operating envelope testing must be performed for both configurations. Imaging must not be performed when the conditions are outside of the developed operating envelope. Operating envelopes may be developed by a camera manufacturer for a particular OGI camera model and configuration or by others,

8.4 Development of ~~the~~ an operating envelope is to be performed using the test gas composition in either Section 6.2.1 or 6.2.2, flowrate, and orifice diameter described in Section 6.1.2, and must include the following variables:

8.4.1 Delta-T, regulated through the use of a temperature-controlled background encompassing approximately 50 percent of the field of view, with no potential for solar interference;

8.4.2 Viewing distance from the OGI camera to the component being imaged; and

8.4.3 Wind speed, controlled through the use of an industrial fan.

8.5 Determine the operating envelope using the following procedure:

8.5.1 Set up the methane/propane test gas at a flow rate of ~~17~~ 60 g/hr. or setup the methane test gas at a flow rate of 17 g/hr. The same test gas(s) used for demonstrating that the minimum detection limit required in section 6.1.2 must be used when determining operating envelopes.

8.5.2 For this flow rate, the ability of the OGI camera to produce an observable image is challenged by ranges of the variables in Sections 8.4.1 through 8.4.3.

8.5.3 A panel of no less than 4 observers who have been trained using the OGI camera and who have a demonstrated capability of detecting gaseous leaks will observe the test gas release for each combination of delta-T, distance, and wind speed. A test emission is determined to be observed when at least 75 percent of the observers (i.e., 3 of the 4 observers) see the image.

8.5.4 If the pure methane test gas was used, r~~R~~epeat the procedures in Sections 8.5.2 and 8.5.3 using the butane test gas at a flow rate of 18.5 g/hr.

8.5.5 When testing with the pure methane and pure butane test gases, t~~T~~he operating envelope to be used in the field for each OGI camera configuration tested is the more restrictive operating envelope developed between those~~the~~ two test gases.

8.5.6 Repeat the procedures in Sections 8.5.1-8.5.5 for each camera configuration that will be used to conduct surveys in the field.

8.6 The results of the testing to establish ~~the~~ an operating envelope, including supporting videos, must be documented and kept with other OGI records of the organization performing the test. Camera owners must maintain a record of the allowed operating envelope parameters for each camera they own and that record must be readily available to the camera operator.

9.0 Conducting the Monitoring Survey

~~Each site must have a~~ A monitoring plan that describes the procedures for conducting a monitoring survey at each site must be readily available to the camera operator. At a minimum, the monitoring plan must include the following:

9.1 A description of ~~Prior to imaging, the operator must perform~~ a daily verification check to be performed prior to imaging to confirm that the camera is operating properly. This verification must consist of the following at a minimum:

9.1.1 Confirm that the OGI camera software loads successfully and does not display any error messages upon startup;

9.1.2 Confirm that the OGI camera focuses properly at the shortest and longest distances that will be imaged;

9.1.3 Confirm that the OGI camera produces a live IR image using a known emissions source, such as a butane lighter or a propane cylinder;

~~9.1.4 Confirm that the OGI camera can record data and/or leak footage properly by using the~~

~~check in Section 9.1.3 as a test run and saving the resulting file with the survey record; and~~

9.1.~~5~~4 Confirm that the OGI camera can perform the delta-T check function as expected, if this function will be used meet the requirement in Section 9.2.3.

9.2 The ~~site must develop~~monitoring plan must include a procedure for ensuring that the monitoring survey is performed only when conditions in the field are within the operating envelope established in Section 8. This procedure must include the following:

9.2.1 Determination of the camera operator's maximum viewing distance from the surveyed components, based upon wind speed and expected delta-T at the monitoring site. This determination must be made each day a survey is conducted.

9.2.2. Description of how the viewing distance from the surveyed components, the wind speed, and the delta-T will be monitored to ensure that the monitoring survey is conducted within the limits of the operating envelope;

9.2.3 Description of how the operator will ensure an adequate delta-T is present in order to view potential gaseous emissions, (e.g., using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view);

9.2.4 Description of how the operator will recognize the presence of and deal with potential interferences and/or adverse monitoring conditions, such as steam, fog, mist, rain, solar glint, extremely high concentrations of particulate matter, and hot temperature backgrounds;

9.2.5 Description of how the operator will deal with changes in site conditions during the survey, especially as it relates to the camera operator's maximum viewing distance.

~~9.3 The site must conduct monitoring surveys using a methodology that ensures that all the regulated components within the unit or area are monitored. This must be achieved using one of the following three approaches. The approach chosen and how the approach will be implemented must be described in the monitoring plan. The use of a component database can help make the survey process more efficient, but, the component database is not a substitute for the approaches described below.~~

~~9.3.1 Use of a route map or a map with designated observation locations. The map must be included as part of the monitoring plan, with a predetermined sequence of process unit monitoring (such as directional arrows along the monitoring path) depicted or designated observation locations clearly marked.~~

~~9.3.2 Use of visual cues. The facility must develop visual cues (*e.g.*, tags, streamers, or color-coded pipes) to ensure that all regulated components were monitored. The monitoring plan must describe whatvisual cue method is used and how it will be used to ensure all components are monitored during the survey.~~

~~9.3.3 Use of global positioning system (GPS) route tracing. The facility must document the path taken during the survey by capturing GPS coordinates along the survey path, along with date and time stamps. GPS coordinates must be recorded frequently enough to document that all regulated components were monitored. The monitoring plan must describe how often GPS coordinates will be recorded and how the route tracing will ensure all regulated components are monitored.~~

9.3 Your monitoring plan must include procedures to ensure that all equipment leak components as defined in the referencing subpart or permit are monitored. Example procedures include, but are not limited to, a map or electronic database with an observation path or GPS coordinates, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

9.4 The ~~site must develop~~monitoring plan must include a procedure that describes how components will be viewed with the OGI camera. In general, a component should be imaged from at least two different angles, and the operator must dwell on each angle ~~for a minimum of 5 seconds~~ before changing the angle, distance, or focus and dwelling again. For a complex scene of components, the operator must divide the scene into manageable subsections and dwell on each angle ~~for a minimum of 5 seconds per component in the field of view (e.g., for a subsection with 5 components, the minimum dwell time would be 25 seconds)~~. ~~The operator may reduce the dwell time for complex scenes based on the monitoring area and number of components in the subsection as prescribed in Table 14-1, provided the manageable subsection for the angle fills greater than half of the field of view of the camera.~~ The procedure must discuss changes, if necessary, to the imaging mode of the OGI camera that are appropriate to ensure that leaks from all ~~regulated equipment leak~~ components regulated by the referencing subpart or permit can be imaged.

9.5 The monitoring plan must include~~site ownermust have~~ a plan for avoiding camera operator fatigue, as physical, mental, and eye fatigue are concerns with continuous field operation of OGI cameras. ~~The OGI camera operator should not survey continuously for a period of more than 20 minutes without taking a rest break. Taking a rest break between surveys of process units may satisfy this requirement; however, for process units or complex scenes requiring continuous survey periods of more than 20 minutes, the operator must take a break of at least 5 minutes after every 20 minutes of surveying.~~

~~Note: If continuous surveying is desired for extended time periods, two camera operators can alternate between surveying and taking breaks.~~

9.6 The monitoring plan must include~~site owner must have~~ a procedure for documenting monitoring surveys, including:~~.~~

9.6.1 For each monitoring ~~survey~~day or change in facility, record the date and approximate start and end times.

9.6.2 At the start of ~~the survey~~each monitoring day or a change in facility~~, when transitioning to the next major process area, and at the end of the survey~~, record the weather conditions, including ambient temperature, wind speed, relative humidity, and sky conditions.

9.7 The site must have a procedure for documenting fugitive emissions or leaks found during the monitoring survey.

9.7.1 If a leak is found and the leak is not immediately repaired, the leaking component must be tagged for repair or an image obtained to show the location of the leak. If the component is not immediately repaired or tagged, ~~at a minimum~~ capture a digital image or at a minimum a 10-second video clip of the leaking component and keep the video clip or digital image with the rest of the OGI survey documentation. ~~The leaking component must be tagged for repair, and~~ T~~t~~he date, time, and location of ~~the~~ all leaks must be recorded and stored with the OGI survey records. ~~This information can be used to visually assist the operator with locating components that need repair.~~

9.7.2 If no emissions are found, no recorded footage is required to demonstrate that the component was not leaking.

~~9.7.3 At least once each monitoring day, each operator must record a quality assurance (QA) verification video that is a minimum of 5 minutes long. The video must document the procedures the~~

~~operator uses to survey *(e.g.*, dwell times, angles, distances, backgrounds) and the camera configuration.~~

9.8 The ~~site's~~ monitoring plan must describe the process that will be used to ensure the validity of the monitoring data as detailed in Section 11.

10.1 The facility or company performing the OGI surveys must have a training plan which ensures and monitors the proficiency of the camera operators. Training should include ~~classroom~~ instruction and field training on the OGI camera and external devices, monitoring techniques, best practices, process knowledge, and other regulatory requirements related to leak detection that are relevant to the facility's OGI monitoring efforts. ~~If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement.~~ Certified thermographers are exempt from the requirements of paragraphs 10.2 through 10.4.

10.2 Prior to conducting monitoring surveys, camera operators must complete initial training and demonstrate proficiency with the OGI camera and any external devices to be utilized for detecting a potential leak.

10.2.1 At a minimum, the training plan must include the following ~~classroom~~ training elements as part of the initial training:

10.2.1.1 Key fundamental concepts of the OGI camera technology, such as the types of images thecamera is capable of visualizing and the technology basis (theory) behind this capability.

10.2.1.2 Parameters that can affect image detection (*e.g.*, wind speed, temperature, distance,background, and potential interferences).

10.2.1.3 Description of the components to be surveyed and example imagery of the various types ofleaks that can be expected.

10.2.1.4 Calibration, operating, and maintenance instructions for the OGI camera used at the facility.

10.2.1.5 Procedures for performing the monitoring survey according to the ~~site~~ applicable monitoring plan, including the daily verification check; how to ensure the monitoring survey is performed only when the conditions in the field are within ~~the~~ an established operating envelope; the number of angles a component or set of components should be imaged from; how long to dwell on the scene before changing the angle, distance, and/or focus; how to improve the background visualization; the procedure for ensuring that all ~~regulated~~ equipment leak components regulated by the referencing subpart or permit are visualized; required rest breaks; and documenting surveys.

10.2.1.6 Recordkeeping requirements.

10.2.1.7 Common mistakes and best practices.

10.2.1.8 Discussion on the regulatory requirements related to leak detection that are relevant to thefacility's OGI monitoring efforts.

10.2.2 At a minimum, the training plan must include the following field training elements as part of the initial training:

10.2.2.1 A minimum of 10 ~~site~~ 20-minute monitoring surveys with OGI where ~~the~~ trainees ~~is~~

~~observing~~ observe the techniques and methods of a senior OGI camera operator (see definition in Section 3.0) who reinforces the ~~classroom~~ training elements.

10.2.2.2 A minimum of ~~40~~ 5 20-minute monitoring~~site~~ surveys with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and ~~provides~~ providing instruction/correction where necessary.

10.2.2.3 A minimum of 50 20-minute monitoring ~~site~~ surveys with OGI where the trainee performs ~~the~~ monitoring surveys independently with ~~the~~ a senior OGI camera operator trainer present and the senior OGI camera operator ~~provides~~ providing oversight and instruction/correction to the trainee(s) where necessary.

10.2.2.4 A final ~~site~~ 1-hour monitoring survey test where the trainee conducts the OGI survey and a senior OGI camera operator follows behind with a second camera to confirm the OGI survey results. Ninety percent agreement on the number of persistent leaks found or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified ~~The trainee~~ must be achieved ~~zero missed persistent leaks relative to~~for the ~~senior~~ OGI camera ~~operator~~ trainee to be considered authorized for independent survey execution. If the required agreement is not achieved, the senior OGI operator must counsel the trainee and then another 1-hour test performed. If there is a lack of adequate agreement on the second test the trainee must complete the refresher training requirements in paragraph 10.3, before taking the final test again.

10.3 Refresher training.

10.3.1 All OGI camera operators must attend a~~n annual~~ ~~classroom~~ training refresher every three years. This refresher can be shorter in duration than the initial classroom, computer or on-line training but must cover all the salient points necessary to operate the camera (e.g., performing surveys according to the monitoring plan, best practices, discussion of lessons learned throughout the year). OGI camera operators who have not performed any OGI monitoring in the last 12-months, must take refresher training before restarting monitoring.

~~10.2.3~~10.3.2 OGI camera operators with at least 24 hours of OGI monitoring experience in the previous 12-months, but no experience operating under Appendix K, must take refresher training per paragraph 10.3.1 and pass a final test per paragraph 10.2.2.4.

10.4 Performance audits for all OGI camera operators, except senior OGI camera operators, must occur on ~~a quarterly~~an annual basis with at least ~~one~~ three months between two consecutive audits. Performance audits must be conducted according to procedures outlined in the monitoring plan. ~~one of the following procedures~~Performance audit procedures may include, but are not limited to paragraphs 10.4.1 or 10.4.2 of this section:

10.4.1 Performance audit by comparative monitoring. Comparative monitoring in near real-time is where a senior OGI camera operator reviews the performance of the employee being audited by performing an independent monitoring survey.

10.4.1.1 Following the survey conducted by the camera operator being audited, the senior OGI camera operator will conduct a survey of the same equipment of at least ~~4~~1-hour~~s~~ ~~to ensure that no persistent leaks were missed~~.

10.4.1.2 If there is less than 90% agreement in the number of~~a~~ persistent leaks identified or a difference of more than 1 persistent leak if less than 10 persistent leaks are identified~~ is missed by the camera operator being audited~~, then the camera operator being audited will need to retrain on the monitoring aspects believed deficient. ~~following the field portion of the initial training outlined in Section 10.2.2. For the retraining, the required number of site surveys with OGI is reduced to 5 full side-by-side comparative surveys in Section 10.2.2.2 and 10 supervised surveys in Section 10.2.2.3before t~~The audited camera operator must ~~achieve zero missed persistent leaks on the final survey test to be recertified~~then repeat the paragraph 10.4.1.2 comparative monitoring test.

10.4.2 Performance audit by ~~video~~ observational review. The camera operator being audited must submit unedited and uncut video footage of their OGI survey technique to a senior OGI camera operator for review or a senior OGI camera operator must visually observe the camera operator.

10.4.2.1 The ~~videos~~ observation period must ~~contain~~be at least ~~4~~ 1 hour~~s~~ of~~ survey footage~~. ~~If a single survey is less than 4 hours, footage from multiple surveys may be submitted; however, all videos necessary to cover a 4-hour period must be recorded and submitted for review.~~ The senior OGI camera operator will review the survey technique of the camera operator being audited, as well as look for any missed leaks.

10.4.2.2 If there is less than 90% agreement in the number of~~the senior OGI camera operator finds any~~ persistent leaks ~~missed by the camera operator being audited~~identified or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified or the auditor finds that the survey techniques during the ~~video~~ review do not match the monitoring plan required by Section 9, then the camera operator being audited will need to retrain on the monitoring aspects believed deficient.~~the field portion of the initial training outlined in Section 10.2.2~~. ~~For retraining, the required number of site surveys with OGI is reduced to 5 full side-by-side comparative surveys in Section 10.2.2.2 and 10 supervised surveys in Section 10.2.2.3 before the audited camera operator must achieve zero missed persistent leaks on the finalsurvey test to be recertified.~~ The audited camera operator must then repeat the paragraph 10.4.2 observational test.

~~10.4.3 If a camera operator is not scheduled to perform an OGI survey during a quarter, then the audit must occur with the next scheduled monitoring survey.~~

~~10.5 If an OGI camera operator has not conducted a monitoring survey in over 12 months, then they must repeat the initial training requirements in Section 10.2.~~

11.0 Quality Assurance and Quality Control

11.1 As part of the facility's monitoring plan, the facility must have a process which ensures the validity of the monitoring data. Examples may include routine review and sign-off of the monitoring data by the camera operator's supervisor, periodic comparative monitoring using a different camera operator as part of a continuing training verification plan described in Section 10, or other due-diligence procedures. The monitoring plan must also include specifics of the annual performance audit procedures that will be used to comply with paragraph 10.4.

~~11.2 Daily OGI camera verification must be performed and a brief (5-10 second) video recorded as described in Section 9.1. Additionally, the daily QA verification video for each operator must be recordedas described in Section 9.7.3.~~

~~11.3~~11.2 The following table is a summary of the mandatory QA and quality control (QC) measures in this protocol with the associated frequency and acceptance criteria. All of the QA/QC data must be documented and kept with other OGI records.

Summary Table of QA/QC

Parameter	**QA/QC Specification**	**Acceptance Criteria**	**Frequency**
OGI Camera Design	Spectral bandpass range	Must overlap with major absorption peak of the compound(s) of interest as specified in paragraph 6.1.1.	Once prior to conducting the initial survey~~s~~ of an area and any time the compounds of interest is expected to change due to process changes.
OGI Camera Design	Initial camera performance verification	Must be capable of detecting (or producing a detectable image of) a 10,000 ppmv methane/propane mixture at 60 g/hr. or of methane emissions of 17 g/hr and butane emission of 18.5 g/hr at a viewing distance of 2 meters and a delta-T of 5 °C in an environment of calm wind conditions around 1 m/sor less. (Paragraph 6.1.2)	Once for each camera model or configuration prior to conducting initial surveys.
Developing the Operating Envelope	Observation confirmation	Leak is observed by 3 out of 4 panel observers for specific combinations of delta-T, distance, and wind speed. (Paragraph 8.5)	Once prior to conducting surveys and prior to using a new camera model or configuration.
OGI Camera Functionality	Verification Check	Meet the requirements of Section 9.1 to confirm that the OGI camera software loads successfully and that the camera focuses properly, produces a live IR image, records, and, as applicable, performs the delta-T check function.	Each monitoring day, for each camera prior to conducting a survey with that camera.
Camera Operator Training	Classroom, computer or on-line training	Meet the requirements of Sections 10.2.1 and 10.3 with the issuing of a certificate or record of attendance kept in the employee or OGI records file.	Prior to a camera operator conducting surveys, with a~~n~~ triannual refresher, and after prolonged periods (greater than 12 months) of not performing OGI surveys.
Camera Operator Training	Field training	Meet the requirements of Section 10.2.2 while maintaining the records of facilities ~~visited~~ monitored by the trainee in the employee or OGI records file along with a certificate or record of completion ~~issued upon the achievement of zero missed persistent leaks~~ of the final survey test specified in paragraph 10.2.2.4 with the date of the survey recorded.	Prior to a camera operator conducting surveys and after prolonged periods (greater than 12 months) of not performing OGI surveys.

~~OGI Camera Operator Performance~~	~~QA verification video~~	~~Record a video that is a minimum of 5 minutes long that documents the procedures the operator uses to survey *(e.g.*, dwell times, angles, distances, backgrounds) and the camera configuration.~~	~~Each monitoring day.~~
OGI Camera Operator Performance	~~Quarterly~~ Annual performance audits	Comparative monitoring: ~~No missed~~Ninety percent agreement on the number of persistent leaks over a ~~4~~1-hour survey as determined by a senior OGI camera operator's survey. OR Video review: Ninety percent agreement on the number of ~~No missed~~ leaks as determined by a senior OGI camera operator and OGI survey technique in submitted videos matches the requirements in Section 9. OR Other audit procedure specified in the applicable monitoring plan.	Every ~~3~~ 12 months, with at least ~~1~~ 3 month between consecutive audits.

12.0 Recordkeeping

12.1 Records required by this Appendix must be kept~~The facility must keep the records required by this protocol~~ for a period of 5 years, unless otherwise specified in an applicable subpart.

12.2 The following records must be maintained, as applicable.~~The facility must maintain the following records in a manner that is easily accessible to all OGIcamera operators:~~ Applicable site monitoring plans and operating envelope limitations must be readily accessible to the camera operators.

12.2.1 Complete site monitoring plan with all the required elements;

12.2.2 Initial OGI camera performance verifications;

12.2.3 Camera maintenance and calibration records over the lifetime of the OGI camera; and

12.2.4 The OGI camera operating envelope limitations.

12.3 All data supporting development of the operating envelope must be maintained by the organization that develops an operating envelope.

12.4 The training plan, and for each OGI camera operator, the following records must be maintained by the employer of the OGI camera operator or the owner or operator of a location being surveyed, as applicable. These may be kept in a separate location for privacy but must be easily accessible to program administrators and available for review if requested by the Administrator: For certified thermographers, these records are not required but a record of the thermographer's certification and date of its expiration is required.

12.4.1 The date of completion of initial OGI camera operator classroom, computer or on-line~~-~~ training;

12.4.2 The date of the passed final ~~site~~ survey test following the initial OGI camera operator field training;

12.4.3 The number and date of all training surveys performed, and if the survey is part of initial field training or retraining, notation of whether the survey was performed by observing a senior OGI camera operator, side-by-side with a senior OGI camera operator, or with oversight from a senior OGI camera operator;

12.4.4 Performance audit methodologies.

~~12.4.4~~12.4.5 The date and results of ~~quarterly~~ annual performance audits; and

~~12.4.5~~12.4.6 The date of any~~the annual classroom~~ training refresher.

12.5 Monitoring survey results shall be kept ~~in a manner that is accessible to those technicians executing repairs~~ and at a minimum must contain the following:

12.5.1 Daily verification check;

~~12.5.2 Camera operator's maximum viewing distance for the day, based upon wind speed and expected delta-T at the monitoring site.~~

~~12.5.3~~12.5.2 Identification of the ~~site~~facilities surveyed and the survey date and start and end times;

~~12.5.4~~12.5.3 Name of the OGI camera operator performing the survey and identification of the OGI camera used to conduct the survey. The identification of the OGI camera can be the serial number or an assignedname/number labeled on the camera, but it must allow an operator or inspector to tie the camera back to the records associated with the camera (*e.g.*, maintenance, initial performance verification);

~~12.5.5~~12.5.4 Weather conditions, including the ambient temperature, wind speed, relative humidity, and skyconditions, at the start of the ~~survey~~monitoring day~~,~~ and when ~~transitioning to the next major process area~~changing the facility being surveyed~~, and at the end of the survey~~;

12.5.5 Video footage or digital photo of any leak detected and not immediately repaired or tagged along with the date, time, and component location of all leaks detected. This video or digital record shall be maintained in a manner that is accessible to those technicians executing repairs; and

12.5.6 Records identified in the monitoring plan to demonstrate that all equipment leak components are monitored per paragraph 9.3.~~The daily QA verification video for each operator; and~~

12.5.7 ~~GPS coordinates for the route taken, if Section 9.3.3 is used to ensure all regulated components are monitored.~~

13.0 References

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~~*14.0 Tables, Diagrams, and Flow Charts*~~

~~Table 14-1. Dwell Time (in seconds) by Subsection Area and Scene Complexity~~

	~~**Components in Subsection**~~				
~~**Monitoring Area (m^2)**~~	~~**2-3**~~	~~**4-5**~~	~~**5-10**~~	~~**10-20**~~	~~**>20**~~
~~**0.125**~~	~~5~~	~~10~~	~~15~~	~~20~~	~~25~~
~~**0.25**~~	~~5~~	~~15~~	~~20~~	~~25~~	~~30~~
~~**0.50**~~	~~10~~	~~15~~	~~25~~	~~30~~	~~*~~
~~**1.0**~~	~~10~~	~~20~~	~~30~~	~~*~~	~~*~~
~~**>1.0**~~	~~*~~	~~*~~	~~*~~	~~*~~	~~*~~

~~* The camera operator must either reduce the subsection volume, the scene complexity, or both by moving closer to the components or changing the viewing angle.~~

~~The operator must divide the scene into manageable subsections and image each subsection from at least two different angles. The dwell time for each angle must be a minimum of 5 seconds per component in the field of view. The operator may reduce the dwell time based on the monitoring area and number of components as described in this table, provided the manageable subsection for the angle fills greater than half of the field of view of the camera. The depth of components within the monitoring area must be less than 0.5 meters.~~

Attachment C

Cost Effectiveness Evaluation for Retrofit of Existing Pneumatic Controllers

Introduction

The purpose of this analysis was to identify the minimum number of controllers that would be cost-effective to retrofit at existing well sites, central tank batteries, and compressor stations based on API member cost information. We utilized EPA's model plant analysis, which was provided by EPA in a Microsoft Excel Workbook *'Pneumatic Controllers Costs and Emissions.xlsx'.* Our review of the model plant analysis determined some assumptions made by EPA should be re-evaluated. Our analysis includes the following updates:

- *Assumptions on the types of reliable technologies available to retrofit pneumatic controllers to non-emitting,*
- *Assumptions of the capital and annual operating costs for these technologies,*
- *Assumptions regarding the ratio of pneumatic controller types at an average facility (what EPA refers to as a model plant), and*
- *Assumptions on the emission factor applied for intermittent controllers that would be part of a monitoring and repair program (which EPA also proposed under fugitive emission monitoring).*

Costs

EPA assumed companies would use grid power or solar systems to power electric controllers. For grid power scenarios, EPA costs were limited to the costs of controllers ($4,000 each) and a control panel for grid connection ($4,000). For solar power scenarios, EPA costs were limited to the cost of electric controllers ($4,000 each), a control panel ($4,000), a single 140 W solar panel ($500), and 100 Amh batteries ($400 each). EPA also included installation and engineering costs based on 20% of equipment costs, with total estimated installation costs varying between $4,420 and $8,040. EPA did not include any annual operating or maintenance costs within their assumptions.

API members have converted natural gas driven pneumatic controllers to compressed instrument air systems powered by the grid (when accessible) or natural gas/diesel generators.[1] Costs associated with a typical instrument air system include a regenerative dryer, inlet filter, tank to store compressed air, insulated enclosure for the compressor and dryer, junction box, controllers for the compressor system, and voltage boosters. Additional costs for solar based systems would include higher cost gel or AGM batteries, sufficient number of batteries, and higher numbers of solar panels required in areas of less sunlight such as for Wyoming and North Dakota. Additional costs associated with use of natural gas or diesel generators to power instrument air systems might also include monthly rental fees.[2] An instrument air system typically also requires annual maintenance at a cost of between $2,000 and $4,000 per year depending on the size of the system.

Through a blinded survey conducted a third party, API members provided cost data for converting pneumatic controllers to non-emitting. For smaller facilities, the average cost for a grid powered

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[1] API members are only in initial phases of testing the reliability of solar based instrument air systems and costs are not available for a smaller installation.

[2] Monthly rental fees for a third-party generator can run between $8,000 upwards of $25,000 based on the size of the facility. We did not include these additional fees in this analysis.

instrument air system was estimated at $51,000 and for a natural gas generator powered instrument air system around $60,000. These costs include equipment and installation costs. There are also annual maintenance costs associated with both types of systems as mentioned above. For our analysis, we assume an average annual maintenance cost of $3,000.

Count of Controllers

EPA assumed that for existing site retrofits the small, medium and large model plants each contained a high bleed pneumatic controller. This is an incorrect assumption, which is supported by data reported to EPA pursuant to 40 CFR Part 98, subpart W. Data extracted from Envirofacts for the 2020 calendar year clearly shows the breakdown of high bleeds is only 1% for the production segment and 3% for the gathering and boosting segment as summarized in Table C-1. For our analysis, we utilized the assumption that there are 30% continuous low bleed controllers and 70% intermittent controllers at an existing facility.

Table C-1. Counts of Pneumatic Controllers Reported for the 2020 Calendar Year pursuant to 40 CFR Part 98, Subpart W

2020 Reporting Year GHGRP Data	Onshore petroleum and natural gas gathering and boosting [98.230(a)(9)]		Onshore petroleum and natural gas production [98.230(a)(2)]	
Device Type	**Count**	**% of total**	**Count**	**% of total**
High-Bleed Pneumatic Devices	4,067	3%	11,292	1%
Intermittent Bleed Pneumatic Devices	93,202	69%	592,456	72%
Low-Bleed Pneumatic Devices	38,153	28%	221,612	27%
Total	135,422	100%	825,360	100%

Emission Factors

As documented in API's Compendium of GHG Emission Methodologies for the Natural Gas and Oil Industry[3] in Table 6-15:

- The average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or the monitoring status is unknown.
- The normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program.

When intermittent controllers are properly functioning, gas is typically emitted only when the controller actuates. Since EPA has proposed to include intermittent controllers within the fugitive emission monitoring requirements, the intermittent controller would be monitored routinely and repaired or replaced if malfunctioning. Therefore, the more appropriate emission factor that should be utilized for

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[3] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

the pneumatic controller analysis is the properly functioning intermittent controller emission factor of 0.28 scf whole gas/controller-hr and not the average emission factor of 9.2 scf whole gas/controller-hr that EPA applied in their analysis.

Results

Our review indicates that it is not cost effective (as prescribed by EPA) to retrofit gas driven controllers to non-emitting unless there are at least 15 to 30 controllers at an existing site, depending on the single or multi-pollutant approach that EPA typically uses for evaluation. Our results, which follow the analysis format outlined by EPA, are provided in Table C-2.

Table C-2. Cost-Effectiveness Determination for the Minimum Number of Controllers that Should be Considered for Retrofit

Model Plant	Control Option[a]	Count of Controllers[b]	Emissions Reduction- Per Facility (tpy)[c]		Capital Cost[d]	Without Savings					With Savings				
						Annual Cost ($/yr)[d]	Cost Effectiveness ($/ton)		Multipollutant Cost Effectiveness ($/ton)		Annual Cost ($/yr)[d]	Cost Effectiveness ($/ton)		Multipollutant Cost Effectiveness ($/ton)	
			VOC	Methane			VOC	Methane	VOC	Methane		VOC	Methane	VOC	Methane
Minimum # of controllers Multi-Pollutant	Grid power Instrument air system	15	0.66	2.36	$51,000	$8,600	**$13,980**	**$3,886**	$6,990	$1,943	$8,198	**$13,327**	**$3,705**	**$6,664**	**$1,852**
	Natural gas generator instrument air system		0.66	2.36	$60,000	$9,588	**$15,586**	**$4,332**	$7,793	$2,166	$9,186	**$14,933**	**$4,151**	**$7,467**	**$2,076**
Minimum # of controllers Single Pollutant	Grid power instrument air system	30	1.31	4.72	$51,000	$8,600	**$6,990**	**$1,943**	$3,495	$971	$7,797	**$6,337**	**$1,762**	**$3,169**	**$881**
	Natural gas generator instrument air system		1.31	4.72	$60,000	$9,588	**$7,793**	**$2,166**	$3,896	$1,083	$8,785	**$7,140**	**$1,985**	**$3,570**	**$992**

a. Grid Power Instrument Air Systems are assumed to be for locations with available onsite grid power access (assuming a step-down transformer is in place).

b. Counts of Controllers include 30% low bleed and 70% intermittent bleed, which is consistent with trends reported to EPA under 40 CFR Part 98, subpart W for the 2020 calendar year.

c. Emission baseline updated to denote use of properly functioning intermittent controller based on Table 6-15 of the Compendium of GHG Emission Methodologies for the Natural Gas and Oil Industry. This change will appear in the Emission Reduction - Per Facility Columns for methane and VOC.

d. Costs updated to reflect API member company data presented in Table 3 of API comment document (refer to Comment 2.8) based on technologies currently being deployed. This includes an additional $3,000 of annual maintenance costs to ensure instrument air system is functioning properly. Cost info updates are denoted by red font.

Attachment D

API Comments on EPA’s Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks

American
Petroleum
Institute

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November 16, 2021

Ms. Melissa Weitz
U.S. Environmental Protection Agency
Climate Change Division (6207A)
Office of Air and Radiation
1200 Pennsylvania Avenue, NW
Washington, DC 20460
GHGInventory@epa.gov

Re: API Comments on EPA's Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks

Dear Ms. Weitz,

The American Petroleum Institute (API) appreciates the opportunity to review and provide comments on the proposed updates the U.S. EPA is considering for estimating greenhouse gas (GHG) emissions for the 2022 GHG Inventory (GHGI). The current set of comments addresses the methodologies outlined in EPA's September 2021 technical memoranda on: (a) abandoned oil and gas wells; (b) post-meter emissions; (c) use of Gas Star and Methane Challenge reductions; (d) midstream activity data; and (e) emissions from anomalous well events.

API represents all segments of America's natural gas and oil industry. API was formed in 1919 as a standards-setting organization. In our first 100 years, API has developed more than 700 standards to enhance operational and environmental safety, efficiency, and sustainability. Our 600 members produce, process, and distribute most of the nation's energy. Most of our members will be directly impacted by the way emissions from their operations are depicted in the national GHGI.

API's aim is to make sure that the GHGI emission estimates used are based on the best and most current data available, reflect actual industry practices and activities, and are technically correct. To assist EPA in the endeavor API has participated in EPA's stakeholders' process and expert review phases of the GHGI development process, providing comments and recommendations on the agency's proposed methodologies. API appreciates the continued engagement with EPA through the multi-stakeholders process.

API's comments below are designed to provide feedback on the information the Agency is seeking from industry along with additional input to inform the proposed updated methodologies. For some of the updates under considerations API is providing supplemental information while for others API recommends that EPA reconsider the merit of adopting the proposed revised methodologies, at this time, without allowing additional time for obtaining information about relevant practices.

***Updating Abandoned Wells methodology*[1]**

- API commented previously on Abandoned Wells emissions when EPA introduced the update for the 2018 GHGI. API noted that the studies conducted so far have limited geographical coverage and may not be nationally representative. To clarify, EPA uses the "entire US" emission factors from the Townsend-Small study, which include the much higher Eastern US (Appalachian - Ohio) emission factors. They then use these same Eastern US factors from Townsend-Small coupled with emissions from Kang 2016 to develop EF's for Appalachian basin abandoned wells. API recommends that EPA should use the lower "western US" emission factors for abandoned wells outside of the Appalachian basin.

- Additionally, the Townsend-Small Appalachia data are dominated by one well with emissions of 146 grams/hr that is about an order of magnitude higher than any other well, plugged or unplugged, in the Townsend-Small data. API contends that it is not appropriate to include this well in the emission factor for the entire US. Also, to date no emissions data are available from the state of Texas or many other major producing areas, calling into question the representativeness of the extrapolation of the results of the current studies to a nationwide estimate of the contribution of CH_4 emissions from Abandoned Wells to the GHGI.

- API requests from EPA a better explanation of how it estimated the number of 1.1 million historical abandoned wells, which are not captured in the Enverus database. Moreover, API maintains that EPA should not assume that all historical (pre-Enverus) wells are unplugged, without further supporting information. Looking at the restructured Enverus data at the end of 1975, which is the date EPA used to develop its estimate of historical (pre-Enverus) wells, indicates that 72% of the wells that would be classed as 'abandoned' by the criteria in Table 3 of the 2022 memo are shown as actually 'plugged and abandoned'. Hence, EPA should not ignore the Enverus data in favor of unsupported assumptions.

- API contends that an alternative estimate of historically abandoned wells could be based on data for 'undocumented orphan wells' provided in the 2019 report issued by the Interstate Oil & Gas Compact Commission (IOGCC)[2]. According to the IOGCC 2019 report the total estimated number of undocumented orphan wells reported by the states is between 210,000 and 746,000 (*as shown in Table 1. Total Idle and Orphan Wells: All Surveyed States and Provinces (2018)).*

- API also asks EPA to provide greater insight into the process of restructuring of the Enverus data set and the treatment of dry wells. API notes that the designation of "Dry Wells" in the Enverus database indicate a production type rather than a status type and EPA's approach of considering all wells with no cumulative production as abandoned wells is likely leading to

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[1] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-abandoned-wells_sept-2021.pdf

[2] IOGCC, 2019, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies; https://iogcc.ok.gov/sites/g/files/gmc836/f/documents/2021/2020_03_04_updated_idle_and_orphan_oil_and_gas_wells_report.pdf

double counting of dry wells in the abandoned well category since they are embedded in the well status counts. Furthermore, EPA's assumption that dry wells are unplugged is neither consistent with the Enverus data nor State plugging requirements. Current Enverus data shows that 93% of dry holes are plugged. Texas requires the same plugging standards for dry holes as for idle production wells and other State requirements are believed to be similar.

- Many of the largest producing states have regulations in place spelling out emissions, discharge or integrity requirements that must be met when a well is non-producing. API stipulates that the simple assignment of the 'unplugged' designation to all the status codes that are not 'Excluded' or 'Plugged and Abandoned' (P&A) overlooks the potential impacts of such regulations and is therefore inaccurate. Such regulations, even if not directly promulgated to control volatile emissions, have the potential for lower emission rates from wells that are subject to regulation when inactive*. See Appendix 1 for matrix of state requirements for inactive wells.* API is looking forward to engaging with EPA on the impact of existing regulatory requirements on emissions from abandoned and inactive wells.

- API's analysis of Enverus data does not validate the information in Table 3 of the 2022 Abandoned Wells Update Memo as representative of calendar year 2019. However, the counts in Table 3 are broadly similar to API's analysis of current date Enverus well counts. API requests that EPA should validate that their modified query of the Enverus database for 2019 counts is correct and provide this information to stakeholders in an updated Table 3 if changes are substantive.

- Moving forward API recommends that EPA should continue to use the Enverus production type field, where available, to classify wells into gas vs. oil and should also use the Enverus P&A status for determining what dry holes are unplugged. API further recommends that EPA should continue to use the cumulative production coupled with the well status and production type information to determine the count of dry wells*.*

- API is not aware of alternative, high quality, sources of data readily available to inform the count of abandoned wells or the split into plugged and unplugged categories

Post meter emissions[3]

- API acknowledges EPA's proposed intent to add estimates from post-meter residential, commercial, and industrial customer methane emissions as well as certain natural gas vehicle emissions in accordance with guidance provided in the 2019 Refinement to the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories for natural gas systems (IPCC 2019).

- API recognizes that while post-meter emissions will be part of the Natural Gas Systems chapter of the GHGI, it requests that the data be provided as its own "line item" within natural gas

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[3] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-post-meter_sept-2021.pdf

systems. It should not be included in the distribution segment, which ends at the customer meter.

- For residential post meter emissions, EPA intends to base its estimate on the Fischer et. al. (2018) report[4], which measured CH_4 leak emissions from 75 homes that use natural gas in California. This study is used as the basis for the estimate provided in the CARB state GHG inventory. API observes that the limited regional nature of the 2018 data used for CARB's estimate is not sufficiently large to represent residential gas use and potential CH_4 emissions nation-wide. In the absence of better data API suggests that EPA consider a bifurcated approach that uses other available regional data, such as the Merrin and Francisco (2019), outside of California.

Use of GasStar and Methane Challenge reductions in GHGI[5]

- EPA is assessing the applicability of reductions reported under GasStar and the Methane Challenge voluntary programs for the accounting of emission reductions data to prevent double counting. API supports EPA's intent to remove the current time series of GasStar emission reductions and replace them with an updated series for the span of 1990-2019 for those sources for which 'potential to emit' methodology is still used in the GHGI estimates.

- API objects to EPA's proposal to revise the GasStar emission reductions dataset by applying sunset dates of 7 or 10 years for those emissions, rather than assume that the reductions are permanent. API members, who are also GasStar partners, contend that sunsetting of the "reductions" in the GasStar program were not necessarily related to any lack of efficacy, or "decay", of the reduction or control measures put in place. Adoption of the sunset dates' methodology reflected the goal of the GasStar program to drive additional reductions overtime. Thus it was the credits offered in the programs that were retired, with no indications that the emission reductions ceased or that emissions increased.

Applying midstream activity data updates[6]

- EPA is considering using the Enverus Midstream and PHMSA data to update certain activity data. This would result in potentially significant changes to counts of processing plants, gathering and boosting compressor stations, gathering pipeline miles, and transmission pipeline miles, with a smaller change to the count of transmission compressor stations.

- API support the continued use of current sources of activity data previously used in the GHGI which relied on data reported through the GHG Reporting Program (GHGRP) and other

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[4] Marc L. Fischer, Wanyu R. Chan, Woody Delp, Seongeun Jeong, Vi Rapp, Zhimin Zhu. An Estimate of Natural Gas, Methane Emissions from California Homes. Environmental Science & Technology 2018, 52 (17), 10205–10213; .https://pubs.acs.org/doi/10.1021/acs.est.8b03217

[5] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-gas-starmc_sept-2021.pdf

[6] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-activity-data_sept-2021.pdf

regulatory programs. API does not support moving to the Enverus database without further review and explanation on how the database was developed.

- The current activity data in the GHGI has been developed from regulatory data ensuring alignment of, and achieving consistency with, reported industry data. For example, GHGI 2019 data accounts for 667 natural gas processing plants and represents about a 25% higher count than that available from the EIA 757 survey (479 in EIA, 2017)[7], or the 449 facilities that reported to GHGRP in 2019. This difference may be explained by the regulatory thresholds for the reporting facilities. To compare, the Enverus Midstream database indicates that there are more than double natural gas processing plants (1021 - see Table 6 of EPA September 2021 memo). API is concerned that such a large discrepancy indicates that there might be double-counting of processing plants, which may call into question the reliability of the entirety of Enverus Midstream data.

- API has previously supported the use of PHMSA data for midstream activities and continues to support the use of PHMSA for storage well counts. API affirms that using the PHMSA data uses actual counts versus the current GHGI estimation.

Anomalous Events including Well Blowout and Well Release Emissions[8]

- EPA is considering expanding the estimation of anomalous events from just onshore oil well blowouts to including onshore oil and gas well blowouts and releases. EPA intends to use the existing emission factor and TX RRC extrapolated activity data to estimate blowouts and releases.

- API is concerned over the use of a single emission factor for both oil and gas wells, as well as representing both blowouts and releases. API is seeking more information (with a specific citation) to the "Industry Review Panel" that originally proposed the 2.5 mmcf/event emission factor. API calls on EPA to more precisely distinguish between a well blowout and a well release and explain what the existing distinction is.

- API requests that EPA clarify whether there is a possibility of developing emission factors that are based on the length of the blowout rather than the events count, and further consider whether the TX RRC database can be leveraged to link the activity factor to a set of scaled emission factors, i.e., based on those same qualitative measures by which EPA was able to consider the relative frequencies of blowouts and releases.

- Though API has requested more information regarding the 2.5 mmcf/event EF, API recommends that moving forward for now, EPA continue to apply the current EF (2.5 mmcf/event) to onshore oil well blowouts only. API does not support expanding the use of the current EF to either oil well releases or to natural gas well blowouts and releases without getting

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[7] https://www.eia.gov/naturalgas/ngqs/#?report=RP9&year1=2017&year2=2017&company=Name

[8] https://www.epa.gov/system/files/documents/2021-10/2022-ghgi-update-well_blowouts_releases.pdf

more information, better leveraging TX RRC database, or scaling EFs based on event and well types.

- API supports using measured emissions data or engineering estimates for unique major anomalous leak events when they occur. Such major events need to be evaluated on a case-by-case basis, per IPCC guidelines[9].

API welcomes EPA's willingness to work with industry to improve the data used for the national inventory. API encourages EPA to continue these collaborative discussions including making progress in addressing the new data collected by the API field study on Pneumatic Controllers emissions.[10] As indicated before, API is available to work with EPA to make best use of the information available under the GHGRP, or other appropriate sources of information/data, to improve the national greenhouse gas emission inventory. To that end we await hearing about the agency's next steps with regard to incorporating revisions to the GHGRP.

Sincerely,

Marcus J Koblitz

Marcus Koblitz
Policy Advisor, Climate & ESG Policy
Corporate Policy
koblitzm@api.org

cc. Mark DeFigueiredo, DeFigueiredo.Mark@epa.gov

Attach: Appendix 1. Matrix of State and Federal Well Abandonment Programs

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[9] 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 Energy, 4.2.2.3 CHOICE OF EMISSION FACTOR1 B 2 a vi Other

[10] API, *Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States*, March 2020 (submitted to EPA by memorandum on July 2, 2020)

Attachment B

Previous API Comments on Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems;

Docket No. EPA-HQ-OAR-2023-0234

Proposed Subpart W Revisions

API American Petroleum Institute
AXPC
IPAA Independent Petroleum Association of America
The Petroleum Alliance of Oklahoma
AFPM

October 2, 2023

__Submitted electronically to docket No. EPA-HQ-OAR-2023-0234__

Jennifer Bohman

Climate Change Division, Office of Atmospheric Programs (MC-6207A)
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Docket No. EPA-HQ-OAR-2023-0234

Dear Ms. Bohman:

The American Petroleum Institute, the American Exploration & Production Council, Independent Petroleum Association of America, The Petroleum Alliance of Oklahoma, and the American Fuel and Petrochemical Manufacturers (collectively "Industry Trades") appreciate the opportunity to offer comments to the U.S. Environmental Protection Agency (EPA) on the proposed “Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems” (proposed on August 1, 2023). For perspectives of offshore operators, the Industry Trades encourage EPA to also review the Offshore Operators Committee (OOC) letter and incorporate them by reference herein. With this submittal, the Industry Trades seek to continue our participation in the rulemaking process as a collaborative stakeholder by providing meaningful solutions to simultaneously address EPA’s goals while addressing the burden of data collection (and identifying potential unintended consequences) that could result if the rulemaking is finalized as proposed.

The oil and natural gas industry has participated as key collaborative stakeholders, advancing the EPA Greenhouse Gas Reporting Program (GHGRP) since its inception by contributing expertise and proposing alternatives that reflect the reality of the industry and its evolving day-to-day operating practices. The Industry Trades have focused on providing information that will help inform decision makers and the public about various challenges to data collection and reporting required by the rule, which includes safety, accuracy, and feasibility concerns, as well as the need to protect sensitive information and to ensure that reporting requirements are placed on the correct reporters.

These comments on EPA’s proposed revisions to Subpart W reflect our continued interest in the evolution of the GHGRP to provide an accurate accounting of greenhouse gas (GHG) emissions from facilities across the full value chain of the oil and natural gas industry. Our comments cover concerns and recommendations in the wide range of sectors that relate to the operations of our collective members.

Docket ID No. EPA-HQ-OAR-2023-0234
October 2, 2023

INDUSTRY TRADES' INTERESTS

The **American Petroleum Institute (API)** is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader convening subject matter experts from across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 800 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Additionally, API has a history of working with EPA to refine and improve data collection, emission estimation and emission reporting under various subparts of the GHGRP. API has worked with both EPA and the regulated industry for more than two decades in developing methodologies for estimating greenhouse gas emissions from oil and natural gas operations. API's first *Compendium of GHG Emissions Methodologies for the Oil and Natural Gas Industry* (the *Compendium*) was published in 2001. As reflected in EPA's efforts to revise the GHGRP and API's recent publication of a 4th edition of the *Compendium (November 2021)*, methodologies to estimate and measure greenhouse gas emissions are continually evolving.

The **American Exploration & Production Council (AXPC)** is a national trade association representing 30 of the largest independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of providing positive environmental and public-welfare outcomes and responsible stewardship of the nation’s natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

The **Independent Petroleum Association of America (IPAA)** represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, which will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The **Petroleum Alliance of Oklahoma** (The Alliance) represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. The Alliance’s members produce, transport, process and refine the bulk of Oklahoma’s crude oil and natural gas and play an essential role in providing products and solutions to improve human health and welfare, power the global economy, and make modern life possible. Abundant, clean-burning natural gas has enabled the United States to become the global leader in greenhouse gas emissions reductions. The Alliance’s members have and will continue to deploy technologies that result in meaningful greenhouse gas emission reductions through innovative solutions and breakthrough technologies while meeting the energy demands of today and the future.

American Fuel and Petrochemical Manufacturers (AFPM) is a national trade association whose members comprise most U.S. refining and petrochemical manufacturing capacity. AFPM is the leading trade association representing the makers of the fuels that keep us moving, the manufacturers of the petrochemicals that are the essential building blocks for modern life, and the midstream companies that get our feedstocks and products where they need to go. To receive necessary materials and to move their essential products to satisfy growing demand, AFPM members depend on the timely development of, and enhancements to, transportation infrastructure such as pipelines.

The Industry Trades appreciate EPA's engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize changes to Subpart W that improve accuracy without imposing undue burden on the industry, reflect technological and scientific improvements in methodologies, and incentivize the industry's ongoing efforts to reduce emissions.

The Industry Trades' Comments on EPA's Proposed "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems"

Docket ID: EPA-HQ-OAR-2023-0234

October 2, 2023

Summary of Priority Items

The Industry Trades support certain aspects of the proposed revisions to Subpart W and remain committed to working with the Environmental Protection Agency (EPA) and the Administrator to improve the accuracy of Subpart W reporting in a cost-effective manner, while encouraging continued progress toward reducing greenhouse gas (GHG) emissions. The Industry Trades support accurate emissions reporting for many reasons, however it is particularly important given that reported emissions will form the basis of assessed methane fees as a Waste Emissions Charge (WEC), implemented under the Inflation Reduction Act (IRA). As such, these proposed changes create a potentially significant financial impact on the Industry Trades. Therefore, the Industry Trades provide these comments with a goal of improving accuracy of reported emissions through requirements that are appropriate, implementable, and reflective of actual emissions.[1] The comments herein focus on technical and feasibility challenges with specific provisions that EPA included in the proposed Subpart W rule revisions, while providing viable alternatives that support accurate emissions reporting.

The Industry Trades continue to strongly encourage EPA to find ways to make Subpart W less prescriptive and therefore better poised to not just accommodate but encourage the use of rapidly evolving technologies to detect and minimize emissions.

In addition to our technical comments, the Industry Trades have identified four overarching priority items within the proposed rules that if satisfactorily amended, will allow industry to attain the maximum potential methane mitigation and reduce public confusion. These high priority items are as follows:

1. **Achieve greater inter- and Intra- agency regulatory harmonization and coordination**:

   There are multiple federal agencies and distinct departments within agencies that have pending or proposed regulations, guidance, or frameworks directly and indirectly related to methane emissions applicable to our industry, as listed below:

   a. EPA – New NSPS OOOO b/c regulations
   b. EPA – Revisions to GHG Subpart W methane reporting
   c. EPA – Pending Methane Emissions Reduction Plan (MERP) implementation regulations
   d. Treasury Department – Section 45V regulations for hydrogen production tax credit, with the treatment of differentiated natural gas
   e. DOT/PHMSA – LDAR Rule
   f. DOI/BLM – Waste Prevention Rule
   g. DOE/Argonne – GREET Model, used as the basis for calculating GHGs associated with hydrogen production for eligibility for the Section 45V tax credit
   h. DOE – Differentiated Gas Framework
   i. State Department – International methane MRV standard (with DOE)
   j. State Department – Global discussions on an EU Import standard and global methane policy

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[1] Citations provided in this comment letter refer to the proposed rule, unless indicated otherwise. The structure and order of our comments does not necessarily reflect the individual comments' importance to the Industry Trades and their members. The Industry Trades believe all of its comments will help ensure the rule's integrity and deserve serious consideration.

Across all of this methane-related policy making, the Industry Trades identify a potentially high risk for inconsistent methodologies or reporting structures.

In addition, many states – especially New Mexico and Colorado – have already implemented regulations to mitigate emissions across the oil and gas industry; these likely conflict with the final NSPS OOOOb, EG OOOOc and Subpart W reporting requirements.

We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself. Below are a few examples that are articulated in our comments:

- "Other large release events" should be governed by the Methane Rules Super Emitter Response Program ("SERP"), not by an additional and separate Subpart W notification process.
- The "Other large release event" threshold for pipelines should align with the PHMSA incident threshold.
- Compressor vent measurements should align with the Methane Rules. Subpart W should not mandate additional measurements for those sources.
- Flare requirements should not extend beyond 60.18 "General control device and work practice requirements" and the Methane Rules.
- Combustion emissions for all oil and gas segments should be reported under Subpart C, which is the subpart under which *all other industries* report fuel combustion emissions.

2. **Incentivize Cost-Effective Advanced Methane Detection through Technology Agnostic Rules:**

Advanced methane detection technologies and flexibility to implement them are critical to the industry's ability to fully realize methane emissions reductions. Many operators have invested in technological advancements and have deployed and tested the technologies over many years, demonstrating the success of advanced programs and reaching a firm understanding of their operation and deployment. If this component of the suite of methane rule makings, including in Subpart W, is not expanded, the remaining rules will fail to realize the emission reduction goals.

3. **Accommodate Empirical Data, as a Demonstration of Emission Reductions**:

Provisions must be built into the Subpart W rule so that each operator can demonstrate actual reductions; this would promote consistency, transparency, and accuracy in emissions reporting. For example, reporters are precluded from using readily available empirical data (such as engine performance tests) and are instead required to use static emission factors that were based on limited data sets, which will not be reflect emissions reductions and will disincentivize emission reductions. The Industry Trades have noted throughout our comments where EPA must adjust the rule to accommodate empirical data.

4. **Maintain EPA's GHGRP and Subpart W within it as the Authoritative Source of Reported Emissions**:

There are increasing instances of conflict between Subpart W methodologies with those of permitting agencies, which also conflict with current and proposed LDAR requirements and other state and federal GHG reporting structures. EPA must strive for consistency across all GHG reporting frameworks in order to promote stakeholders' trust and confidence in the data.

In addition to the high priority items listed above, the summary below includes the key comments that are generally applicable to many of EPA's proposed revisions to the Subpart W rule:

- **Many proposed Subpart W requirements would impose high implementation burdens for small accuracy improvements for most sources and overall reported emissions.** This overarching theme applies to numerous proposed requirements, especially flare flow monitoring, flare combustion efficiency reporting, gas composition requirements, liquids unloading, and intermittent-bleed pneumatic devices. The Industry Trades have proposed more efficient and feasible alternatives.

- **EPA has not provided qualitative and quantitative justification to rationalize the proposed requirement to disaggregate current reporting levels in the Onshore Production and Onshore Gathering and Boosting industry segments.** The explicitly references existing definitions of facilities in 40 CFR 98 Subpart W, which includes basin-level reporting for the production and gathering and boosting segments. In this proposed rule, EPA has not clarified how its new proposed level of disaggregated reporting to the site-level results in additional value in understanding the key sources of emissions from a basin. A survey performed by API indicates that the proposed Information Collection Request (ICR) pertaining to the proposed rule significantly underestimates the burden for the impacted sectors that would be required to report individual site level emissions and site IDs. Due to the magnitude of the difference, EPA should provide justification in the form of both qualitative and quantitative results of the costs and benefits of this proposed change and how it aligns with the IRA.

- **Generally, the Industry Trades support the optional use of measured data in addition to EPA or company developed emission factors, when the measured data are appropriate.** Allowing reporters the option to use measured data or emission factors (EPA or company-developed) would increase data accuracy and avoid disincentivizing emission reduction measures. While EPA is increasing the sources for which direct measurement is allowed, there are still some methodologies which only allow the use of prescriptive emission factors and parameters with no alternative options (e.g., flare methane destruction efficiency, fraction of un-combusted gas from engines, crankcase venting). While we support the option to use default emission factors and parameters, requiring reporters to use prescriptive emission factors and parameters in lieu of an option to use directly or representatively measured data disincentivizes deployment of emission reduction measures. Additionally, there are some sources where measured data is required to be used, even if the measured data is infeasible, incomplete or potentially unreliable (e.g., flare flow and composition monitoring, mud degassing methane content). EPA should allow operators to utilize the growing number of technologies with quantification capabilities to report empirical data for source categories covered under Subpart W.

- **Monitoring, measurement or inspection requirements (e.g., flare monitoring, etc.) included in Subpart W should be consistent across other air quality programs.** The Industry Trades are concerned with potentially conflicting monitoring or other compliance requirements between the Greenhouse Gas Reporting Program (GHGRP) and future air quality rulemaking under New Source Performance Standards (NSPS) or other air quality programs under EPA's office of Air and

Radiation. The Industry Trades are recommending that EPA remove prescriptive monitoring, sampling or inspection requirements from the GHGRP and instead reference data made available through requirements in other existing regulations. Furthermore, the Industry Trades suggest that EPA not finalize changes to Subpart W until such time that NSPS OOOOb and EG OOOOc have been finalized, and give another opportunity to provide comments on the proposed updates to Subpart W. It is important to the Industry Trades that there is consistency as opposed to conflicting requirements between the GHGRP and future and current rulemaking under other air quality regulatory programs. Finally, the Industry Trades wish to make clear that monitoring methods should not define emission reporting parameters.

- **EPA should avoid any potential double-counting of emissions across source types. The Industry Trades have identified specific areas with the potential for double-counting.** Since it is expected that the GHGRP will be used to determine associated fees within a methane-fee environment, the Industry Trades are extremely concerned about any source and methodology which could result in double counting emissions, and therefore, double fees. Categories that are particularly susceptible to potential double counting are other large release events and unlit flares; and even between flares and unlit flares, where the proposed Tier 3 destruction efficiency for flares includes unlit flares.
- **EPA must set a period over which submitted GHG reports are considered "final" now that reported emissions will be used as a basis for methane fees.** The Industry Trades are concerned about having to resubmit reports for administrative errors or small corrections in emissions given EPA's historical practice of continually submitting questions regarding previously submitted reports. This would lead to an unworkable situation where additional fees will have to be levied or credited for minor changes in emissions in a methane-fee environment. The Industry Trades recommend a 5% facility-wide reported methane emissions error threshold and only require corrections for emission inventories in the last three full data years.

The following key comments reference specific high priority items that pertain to requirements in the Subpart W proposed rule amendments:

- **EPA's tiered approach to flare "combustion efficiency" is flawed and is not supported by the data cited by EPA in the Technical Support Document.** The Industry Trades are concerned that EPA proposes to override decades of precedent on oil and gas flare monitoring and operation established in federal and state regulations, permits, manufacturer guarantees, and performance tests based on the results of just one limited study. As such, the Industry Trades are requesting EPA to allow performance test data for flare methane destruction efficiency, rather than inappropriate National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements, as aligned with EPA's intent to incorporate empirical data. Further and importantly, the Industry Trades have provided additional data to supplement its position that flare "combustion efficiency" should be a minimum of 95%, or arguably even higher based on data from 132 flares tested in the Permian and Bakken. Please refer to Section 3.8.4.4.
- **EPA's requirement to directly meter or use continuous parametric monitoring to estimate flare volume is technically and economically infeasible, and may actually lead to reporting inaccuracies, especially for low-flow streams.** The Industry Trades propose that EPA allows

reporters the option to continue to use engineering estimates for flare volume. Please refer to Section 3.8.1.

- **There are significant concerns regarding the "other large releases" category relating to third-party reporting, the lack of clarity around what is considered "credible" information, and the thresholds proposed for the source category.** The Industry Trades are concerned that unqualified third-party reports could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear and consistent guidelines across regulatory programs on who would be qualified to provide third-party reports (i.e., the necessary expertise, qualifications, methodology, timeline of sharing detections, etc.). The Industry Trades are also concerned that the use of any credible information may lead to reporters inadvertently using invalid data sources, which can lead to inaccurate emissions and disparity among reporters. Further, EPA's requirement to assume a duration of 182 days if no data is available for the release's start or end date is overly conservative. For these reasons, the Industry Trades request EPA to clearly define the scope of credible information. Further, the thresholds of 100 kg/hr. OR 250 mtCO2e would make events with relatively small durations reportable, which does not appear to be EPA's intent to capture large releases. As such, the Industry Trades request that the thresholds be changed to reflect BOTH a rate and an emissions level per event; at a minimum, the threshold should be changed to '100 kg/hr. AND 250 mtCO2e' (i.e., the 100 kg/hr. rate needs to be paired with a duration of at least 100 hours in order to be equivalent to 250 mtCO2e). Please refer to Section 3.11.1, as well as API's comments in response to Docket ID EPA-HQ-OAR-2021-0317, Section 1 (also included in Annex C of this letter).

- **EPA's assumption that improperly seated thief hatches result in a zero percent control efficiency for controlled tanks is overly conservative and not considered in the TSD. Further, EPA's proposed method to calculate the duration of open thief hatches over-estimates emissions from this source.** The Industry Trades propose that EPA use a bifurcated approach for thief hatches that accounts for when they are fully open or improperly seated, which would have lower expected emissions. Please refer to Section 3.6.2.

- **While the Industry Trades support the flexibility to measure GHG emissions from intermittent bleed pneumatic devices, we request that EPA retain the option to use default population emission factors for sources subject to other regulatory programs.** The Industry Trades do not agree with the requirements to measure and monitor emissions from intermittent bleed devices, especially for sources that will be phased out under the impending methane rules. Please refer to Section 3.1.

- **The Industry Trades request that EPA change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production for consistency and to reflect how the industry owns and operates these facilities**. EPA has incorrectly included centralized production facilities with gathering and boosting, but should instead include them in the production segment where they belong. The Industry Trades also strongly recommend that EPA delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion. Please refer to Section 3.16.

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Docket ID No. EPA-HQ-OAR-2023-0234
October 2, 2023

Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

Docket ID: EPA-HQ-OAR-2023-0234

The comments presented below are arranged by the order of citation in the proposed revisions to the "Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems."

1. Subpart W and the Waste Emissions Charge Program

EPA must present a clear rationale for adding an additional layer to sub-facility-level (i.e., site level) reporting to the onshore production and onshore gathering and boosting segments.

EPA explains in the Proposed Rule that under the current Subpart W, "GHG emissions and activity data are currently generally reported at the basin, county/sub-basin, or unit level, depending upon the specific emission source.[2]" According to EPA, this reporting method "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."[3] To resolve those "challenges," EPA proposes "to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments."[4] Furthermore, EPA proposes to require several new site-specific data elements to be reported, including reporting information for individual well identification numbers, well pad identification numbers, and gathering and boosting site identification numbers.[5] In other words, EPA proposes to require site specific reporting in addition to facility-level aggregate reporting.

EPA correctly explains in the Proposed Rule that "[u]nder CAA section 136, an ''applicable facility'' is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution)."[6] As currently defined for onshore production and gathering and boosting, facilities in these segments are generally defined as the equipment located in a single hydrocarbon basin under common ownership or control. The meaning of the term "applicable facility" is key to implementation of the WEC because the applicability of that program and potential fees are determined on an "applicable facility" basis.[7] In the IRA, the definition of an "applicable facility" in the onshore production and gathering and boosting refers to a facility within the applicable segment, as defined in 40 CFR Part 98 at the time of passage of the bill.

Unless EPA proposes updates to facility definitions in 98.238, reporting should remain at the basin-level. Even if EPA were to propose new facility-level definitions in a future rulemaking, there are remaining concerns discussed below.

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[2] 88 Fed. Reg. at 50309.
[3] *Id*.
[4] *Id*.
[5] *Id.* at 50309-10.
[6] 88 Fed. Reg. at 50285.
[7] CAA § 136(c), (e).

EPA's justification for the proposed sub-facility-level reporting requirements is fundamentally flawed because the Agency wholly fails to consider whether the proposed requirements will be adequate to support applicability and fee determinations under the WEC. As noted above, EPA asserts that the new sub-facility-level reporting requirements are needed because the current Subpart W approach "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."[8] These reasons have nothing to do with the primary purpose of this rulemaking – to satisfy the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.[9] Although not related to the WEC, in EPA's Response to Comments in 2009, EPA agreed that oil and natural gas is to be reported at the "upstream" level because further disaggregation would be burdensome to the reporter.[10]

In fact, nowhere in the Proposed Rule does EPA acknowledge that a key driver (if not the key driver) of the proposal is to generate the facility-specific data needed to implement the WEC, nor does EPA provide any analysis or assessment as to whether the new proposed sub-facility-level reporting requirements will be sufficient for that purpose. Unless corrected in a supplemental proposal, that failure to acknowledge and assess a key factor in the rulemaking will render the final rule arbitrary and capricious. *See*, *e.g.*, *Motor Vehicle Mfrs. Assn. of the United States v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has … entirely failed to consider an important aspect of the problem.") The WEC is based on the existing definitions of facilities subject to Subpart W; for that reason, there is no statutory basis to require reporting on a sub-facility-level basis. Basin-level data satisfies the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.

EPA does not explain how the direction in CAA§136(h) in conjunction with CAA § 114 provides authority for EPA to develop extensive requirements in order to collect empirical data.

The text of CAA §136(h) provides:

> (h) REPORTING.—Not later than 2 years after the date of enactment…the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.

Thus, EPA is charged with updating Subpart W reporting to allow for the use of empirical data in reporting methane emissions that will ultimately become the emissions input to calculating the WEC. EPA does not explain in the Proposed Rule how this new congressional direction, layered on top of CAA § 114, provides authority for EPA to develop extensive requirements for installation of monitoring

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[8] I*d.* at 50309.

[9] CAA § 136(h).

[10] ". . . oil and other petroleum products must be reported by refineries, importers, and exporters under Subpart MM. For the proposed rule, EPA decided to require reporting at these points because reporting at natural gas and oil production wells would have been too burdensome and would have resulted in too many reporting facilities, with no improvement in data accuracy.", https://www.regulations.gov/document/EPA-HQ-OAR-2008-0508-2256.

equipment or sampling to acquire empirical data. In the preamble to this Proposed Rule, EPA failed to discuss its definition of empirical data or its views on what costs for implementation would be reasonable for collecting information under the program. Furthermore, in the discussion of new requirements for individual sources under Subpart W, EPA fails to discuss why individual changes are needed to provide empirical data for the purposes of calculating the methane fee. Before issuing a final rule, EPA must provide a thorough discussion of how this limited change to its statutory authority in the IRA provides a basis for these extensive revisions.

Reporting requirements under Subpart W must be reconsidered in light of the role that Subpart W will play in implementing the Waste Emissions Charge Program.

As noted above, key elements of the Proposed Rule are not adequately explained or supported because EPA failed to assess or explain how the proposed new reporting requirements square with the various elements of the WEC. A fundamental aspect of this issue is the fact that the information generated under Subpart W will be used for wholly different purposes under the WEC than it previously was under Subpart W alone. In particular, the emissions information reported under Subpart W will have new and significant legal ramifications because it will be used to determine the applicability of fee determinations under the WEC. So, Subpart W will be extended from a program that provides emissions data for informational purposes to support the development of the national Greenhouse Gas Inventory by EPA into a program that also serves as the compliance assurance component of the WEC. Simply put, this change in the rule now has financial implications for companies.

That expansion in the basic purpose of Subpart W is highly relevant to the Proposed Rule and in meeting EPA's obligation to revise Subpart W to "allow owners and operators of affected facilities … to demonstrate the extent to which a charge under subsection (c) is owed."[11] For example, as explained above, the extent to which "other large release events" should be reported under Subpart W must be established with an eye toward the relevance of the reported information in assessing the applicability and substantive requirements under the WEC program. The same is true of the other "gaps" in Subpart W that EPA proposes to fill in the Proposed Rule.

The rule must also allow an option to use directly or representatively measured data under all sources to demonstrate reductions in emissions. As proposed, not all source categories allow the use of directly measured data to demonstrate true reductions and improvements (i.e., flare combustion efficiency, crankcase venting, and any other area in the rule where reporters are required to use emission factors instead of having the option to directly measure).

Also, emissions information from oil and gas operations is developed to satisfy a wide range of regulatory and non-regulatory obligations beyond the WEC – including to show compliance with the NSPSs and NESHAPs for such operations and to satisfy emissions reporting obligations (e.g., the SEC's proposed disclosure rule). EPA must clearly specify the information needed to implement the WEC and prevent collateral challenges to WEC compliance based on information generated for other purposes under other regulatory programs.

In short, Subpart W is now unique among the GHGRP subparts in that emissions information submitted under Subpart W will serve regulatory purposes not shared by other industries that report under other

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[11] *Id.*

subparts. As a result, EPA now must consider the implications under the WEC program of all Subpart W requirements and explain how Subpart W and the WEC will be integrated into a consistent, coherent, and workable program. EPA's failure to do so in the Proposed Rule constitutes a failure to consider a highly important aspect of the proposal and prevents interested parties from fully understanding, assessing, and commenting on the proposal.

2. 40 CFR Part 98, Subpart A

2.1 Transferred Assets

A new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of a reporting facility.

The Industry Trades acknowledge that EPA has attempted to address concerns over the requirement for a new owner/operator of a reporting facility to be responsible for historical GHGRP reporting prior to the facility's acquisition date by proposing assignment of a "Historical Reporting Representative."

The Industry Trades reiterate concerns highlighted in our October 6, 2022, letter[12] that a new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of any reporting facility. There are several complicated factors that EPA has not addressed as part of this rulemaking.

Proposing a "Historical Reporting Representative" does not guarantee the accuracy of historically reported information. First, there remains no guarantee that the selected representative would maintain access to the critical data systems used to generate the information used for historical GHG reports; once an acquisition is complete, those historical data systems are often no longer accessible by the purchaser (and in some cases, no longer maintained by the seller). While the "Historical Reporting Representative" could provide some anecdotal context around previously submitted reports, there is no guarantee that the "Historical Reporting Representative" would have had "primary responsibility for obtaining the historical information" which would not meet the threshold required for certification from a Designated Representative.[13] This is particularly true when assets are acquired from economically distressed companies which might no longer have any personnel who were involved in any of the historical GHG reports still on staff.

Furthermore, EPA has requested updates to previously submitted reports dating back 5 years and beyond; in many instances, the requested updates do not impact reported emissions and are often simply requests for clarification on certain reporting elements which are solely administrative in nature (e.g., a rolled up total of "Producing" wells in Table AA.1.ii does not match the count of wells labeled

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[12] API Comments to EPA October 6, 2022. https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0322

[13] 40 CFR 98.4(e)(1): Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

"Producing" in Table AA.1.iii). New owners or operators should not be required to update or submit reports for administrative issues which do not impact reported emissions, and EPA should limit the timeframe under which they request additional information or request re-submittals (see Section 2.2, 'Addressing "Substantive" Errors in a Methane-Fee Environment' below).

Currently within EPA's E-GGRT system, there is no way for a new company to access the reports that were previously submitted by the previous owner. Many times when files are transferred, files are missed or it is not clear what was actually submitted by the company. The new owner may not have access to the previous 5 years of submittals and will likely not have access to all the supporting historical records required to generate the report.

The Industry Trades are recommending that EPA require new owners to be responsible for resubmitting or correcting reports only after the point of acquisition, which is further addressed in the below section, 'Addressing "Substantive" Errors in a Methane-Fee Environment.'

2.2 Addressing "Substantive" Errors in a Methane-Fee Environment

A de-minimis threshold and timeframe must be established for errors to be considered substantive.

The Industry Trades reiterate our October 2022 comment that a threshold must be developed by which an error is to be considered substantive. As currently codified, the definition of "Substantive Error" is overly broad; any change, including those that are administrative in nature that do not impact methane emissions, could trigger a re-submittal. Since it is likely that future rulemaking will result in operators paying a methane fee on emissions, it will become increasingly critical for EPA to:

1. Determine a de-minimis "substantive error" threshold for methane emissions that excludes administrative errors that would result in a re-submittal;
2. Limit the timeframe in which EPA can determine that a "substantive error" has occurred; and
3. Limit EPA's validation of re-submitted reports to only the initial potential error.

As methane fees become associated with submitted reports, it will become extremely burdensome to adjust previously submitted payments for changes in a report which could result in very small financial adjustments. Furthermore, as reported emissions result in more financial impacts, the required levels of burdensome review for a change in reported data will increase, even if a change does not result in a change in emissions. For these reasons, Industry Trades are recommending that EPA develop a de minimis threshold for "substantive errors" of 5% of an applicable facility's reported methane emissions. This 5% de minimis threshold for total GHG emissions is aligned with a level of emissions change that many companies use for updating their corporate emissions due to errors and/or acquisitions/divestitures in accordance with the WRI/WBCSD GHG Protocol. While EPA may not know the scope of a possible error when initially requesting additional information, the reporter should have the option to not re-submit the report if an error is found to be below the de minimis threshold, and operators can provide the supporting information in their response to EPA through E-GGRT.

Finally, the Industry Trades are recommending a limit to the timeframe in which EPA can determine that a substantive error has occurred. The Industry Trades recommend that EPA limit the timeframe in which a "substantive error" can result in a requirement to resubmit a prior year's report to no more than three years, consistent with the record retention requirement in 40 CFR 98.3(g). Further, for re-submittals, EPA should limit the validation to the requested source(s) for which the substantive error was identified. This will avoid the burden of the current practice of EPA re-opening inquiries for other sources that previously have already been addressed by the reporter. This still allows EPA plenty of time for review and questions.

3. 40 CFR Part 98, Subpart W

3.1 Pneumatic Devices

Given the proposed zero-emitting standard in NSPS OOOOb and EG OOOOc, EPA should alleviate the burden with measuring and monitoring emissions across the proposed methodologies from natural gas driven pneumatic controllers during their transitional phase out in upcoming years.

Under NSPS OOOOb and EG OOOOc (§60.5390b and §60.5394c), EPA has proposed a zero-emitting standard for natural gas driven pneumatic controllers that, if finalized as proposed, will result in the elimination of methane venting from natural gas driven pneumatic devices, with the exception of those located in Alaska at a site without power. As part of separate comments on the EPA proposed NSPS OOOOb and EG OOOOc, several of the Industry Trades recommended there be limited exceptions to the zero-emitting standard where not feasible and to use the leak detection and repair program monitoring to confirm proper functioning of pneumatic controllers EPA should consider the requirements and timelines that it is proposing across NSPS OOOOb, EG OOOOc, and Subpart W to promote efficiency across the programs and focus on emission reductions.

Given the potential changes to pneumatics under OOOOb and OOOOc, the time period and practicality of using several of the proposed methods for Subpart W may be minimal. As proposed, Method 1 in §98.233(a)(1) requires installation of permanent flowmeters on equipment that will eventually be removed from service. As proposed, Method 2 would require direct measurements on all natural gas driven pneumatic devices over a several year period that corresponds to expected timelines under NSPS OOOOb and EG OOOOc. Method 2 would require purchasing new measurement equipment and training technicians on their operation, which would have a limited window of use with timelines in NSPS OOOOb and EG OOOOc.

Based on the complexities noted above, Method 3 will likely be utilized by many operators for Subpart W reporting. While the Industry Trades support the intent of proposed Method 3, this option also currently includes undue burden for estimating emissions from devices that will, for the majority, not be in operation within the next decade.

Therefore, the Industry Trades offer the following recommendations, which we describe in more detail in the following comments:

- For natural gas driven pneumatic controllers that are not measured under Method 1 or Method 2 or monitored for proper function under Method 3, EPA should allow the use of the single whole gas population emission factor for intermittent-bleed devices (refer to Section 3.1.1).
- EPA should allow an optional estimation of properly operating intermittent-bleed pneumatic controllers using equipment-specific engineering calculations, or a facility-specific properly operating emission factor based on direct measurement. We elaborate on the details further in Section 3.1.3.
- Amend the proper functioning and malfunctioning emission factors for intermittent-bleed devices to include all relevant studies (refer to Section 3.1.3).

- Allow the duration of an intermittent-bleed device malfunction to be determined by repair date or the last monitoring survey (refer to Section 3.1.4).

Note that both Method 2 and 3 provide time horizons for conducting flow measurements or monitoring surveys up to a 5-year cycle depending on the industry segment in which a facility is located. For both onshore production and gathering and boosting, EPA has proposed that operators measure/monitor approximately the same number of devices each year. This timing directly coincides with the implementation of NSPS OOOOb/EG OOOOc and complicates how an operator might track monitoring or measurement results as equipment changes at a facility. Over time, it may be impossible to monitor the same count year-over-year as the total count of natural gas driven devices will reduce over time.

3.1.1 Retain Whole Gas Emission Factor Approach for Intermittent-Bleed Devices

While operators should have the *option* to measure and monitor emissions from those devices, it should not be *required* for sources expected to be phased out as required in other regulatory programs, as this would result in undue capital investment without creating additional value to stakeholders. The proposed methods are highly inefficient and unnecessary considering the required 15-minute measurement time per device or monitoring each device (i.e., OGI or Method 21 screening) for 2 minutes or until a malfunction is identified. The additional burden is not justified considering:

- Any accuracy gain is expected to be temporary considering that proposed federal air quality rules require all pneumatic devices to be transitioned to zero emitting devices;
- Continuous bleed pneumatic devices, a higher emitting source, are allowed to report using an emission factor approach; and
- It penalizes operators who have invested in cleaner technology by replacing continuous high-bleed controllers with intermittent-bleed devices by requiring them to be measured or monitored.

Therefore, **EPA should retain the option to use the default whole gas population emission factor for intermittent bleed pneumatic devices,** as has been proposed under Method 3 for both continuous high- and low-bleed pneumatic devices. Consistent with the derivations used for new emission factors for high and low bleed continuous pneumatic controllers in Table 5-11 of the Technical Support Document for this Rule, EPA suggests the use of 8.8 scf/hr./device for intermittent bleed pneumatic devices, based on a meta-analysis of a variety of field studies. Moreover, many operators are actively working toward voluntarily eliminating most of these sources as they either fall under current or anticipated upcoming state or federal regulations requiring either source control or a zero emissions standard for this equipment. Implementing a burdensome monitoring program for sources that will soon become less significant doesn't make sense. Operators have collectively performed thousands of retrofits to convert continuous high-bleed pneumatic devices into intermittent bleed devices. Operators who acted swiftly should not face more burdensome greenhouse gas accounting requirements, nor should further near-term retrofits be discouraged by imposing disproportionate accounting burdens.

3.1.2 Method 2 – Suggest Improvement in Measurement Cycle and Alternative Approach

The Industry Trades generally support EPA's Calculation Method 2 to distribute measurement campaigns over multiple years where flow monitors are not permanently installed, with the following amendments:

1) Since the as-proposed NSPS OOOOb and EG OOOOc require phase out of this equipment and numerous operators have been reducing these equipment counts voluntarily, it is not possible to

monitor the same number of controllers each year since equipment counts will be simultaneously declining. Instead, **EPA should require the annual inspections to cover at least 20% of the population of pneumatic controllers at a facility** that have not already been inspected pursuant to Subpart W within the previous 4 years, provided that each device remaining in service at the end of the first five years has received at least one inspection over the five-year period.

2) Additionally, EPA should allow operators to **directly measure a representative sample of pneumatic devices in lieu of the entire population.** This approach ensures accuracy of reported emissions but recognizes the vast geographic dispersion of upstream sites. Additionally, API performed a study on the count of pneumatics at upstream sites and provided that in comments regarding the supplemental OOOOb rulemaking.[14] The time required to drive to each site would be unnecessary when a smaller, representative sample accurately reflects the emissions from these devices. Lastly, this approach is incorporated in several voluntary programs (e.g., OGMP 2.0), retains the accuracy of reported emissions, considers the large geographic dispersion of upstream sites, is consistent with the approach proposed for equipment leaks, improves accuracy over generic emission factor-based estimates, and is more cost effective. The representative emission factor approach would require measurement of a representative sample of pneumatic devices to determine a "facility" specific emission factor.

3.1.3 Method 3 – Suggested Amendments to Improve Intermittent-Bleed Device Monitoring

The Industry Trades also generally support EPA's Calculation Method 3; however, **EPA should amend Calculation Method 3 in three important ways**:

1) **EPA should allow the use of a whole gas emission factor as an option for intermittent-bleed devices,** for the reasons stated in Section 3.1.1**.**
2) **EPA should amend Equation W-1C to more accurately reflect available empirical data on emissions from properly functioning pneumatic controllers**, including a broader suite of field data to improve accuracy. Emission factors should incorporate data from additional relevant studies, [15,16,17] one of which is the API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States," where the data and results have been appended to this letter in Annex A. We encourage EPA to utilize the data from this API study, since the API dataset adds 263 additional measurements of intermittent bleed controllers and cover a wide cross section of the industry sectors (production and gathering and boosting sites)[18]

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[14] https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.

[15] Raw data and linked analyses/reports available at http://dept.ceer.utexas.edu/methane/study/. Accessed September 24, 2023.

[16] David T. Allen, Adam P. Pacsi, David W. Sullivan, Daniel Zavala-Araiza, Matthew Harrison, Kindal Keen, Matthew P. Fraser, A. Daniel Hill, Robert F. Sawyer, and John H. Seinfeld. *Environmental Science & Technology* 2015 *49* (1), 633-640. DOI: 10.1021/es5040156

[17] API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States" attached in Annex A and data provided by attachment as an Excel file within this docket.

[18] Note that EPA's comment in the TSD regarding being near or below the OGI threshold for properly functioning controllers using the API field study's emission factor would be resolved by combining the Zimmerle, API, and other relevant datasets to derive properly functioning and malfunctioning emission factors as shown below in Revised Eq. W-1C (the proposed properly functioning emission factor of 0.9 scf/hr/device is equivalent to ~17 g/hr, which is

while the Zimmerle *et al* study only evaluated sites with compression; thus, the resulting bifurcated emission factors would be more accurate and representative. Specifically, **the Industry Trades recommend revision of Eq. W-1C:**[19]

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\left\{\mathbf{20.0} \times T_{mal,z} + \mathbf{0.9} \times \left(T_{t,z} - T_{mal,z}\right)\right\} + \left(\mathbf{0.9} \times Count \times T_{avg}\right)\right] \quad (Rev.Eq.W-1C)$$

Where:

20.0 = Whole gas emission factor for properly functioning intermittent-bleed controllers, scf/hr.

0.9 = Whole gas emission factor for malfunctioning intermittent-bleed controllers, scf/hr.

3) **EPA should allow for the optional estimation of properly operating pneumatic controllers based on equipment specific engineering calculations**, which can be accurately assessed with piping volume, manufacturer actuation data, and average actuation frequency,[20] **or the development of a facility specific properly operating emission factor through direct measurement** of a representative sample of devices across a facility.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\left\{16.1 \times T_{mal,z} + EF_z \times \left(T_{t,z} - T_{mal,z}\right)\right\} + \sum_{y=1}^{y}\left\{EF_y \times T_{t,y}\right\}\right]$$

Where:

z = Count of intermittent bleed pneumatic devices that malfunctioned during the reporting period,

y = Count of intermittent pneumatic devices that properly operated over the entire duration of the reporting period, and

EF = Properly operating emission factor for the specific device or facility.

3.1.4 Intermittent-Bleed Device Survey Improvements

The duration of an intermittent bleed device malfunction should be determined by repair date or other detection approaches, in addition to traditional survey repair verifications.

Operators will have a clear indicator that a malfunctioning device has been returned to properly operating condition based upon the repair date or other detection approaches. EPA should allow for such information to be used for the time input into the malfunctioning controller emission estimation equation, which aligns with EPA's efforts to increase the quality / accuracy of the reported data. For

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above the OGI detection limit). EPA also speculates in the TSD that the API field study included many zero emitting measurements due to the short measurement duration. However, as discussed in the attached paper (see Annex A, pp. 4), the measured emission data points that were below half the effective resolution were conservatively assumed to be half the effective resolution for the minimum instantaneous emission rate in all the analyses. Further, the Allen *et al* 2014 paper conducted a sensitivity analysis which showed that actuations that were just missed by the measurement timeline at 15 minutes had a very small effect on the overall population emission factor estimate.

[19] See Annex F Analysis to support amendment to Calculation 3 for Intermittent Bleed Devices.

[20] https://ogmpartnership.com/wp-content/uploads/2023/02/Pneumatics-TGD-SG-approved.pdf.

example, while conducting AVO inspections, operators can detect that an intermittent device is continuously venting by feeling the gas exit port.

The Industry Trades also support EPA's proposal to retain the option for an operator to apply engineering estimates to determine the time in which the device was in service, in lieu of the default 8760 hours.

Intermittent bleed device surveys should include additional flexibility by allowing audio, visual, and olfactory (AVO) inspections.

Operators should be able to take credit for any surveys, provided those surveys satisfy the intent of the rule. Based on the proposed rule for NSPS OOOOb, facilities subject to NSPS OOOOb monitoring would be required to use non-emitting pneumatic devices. Some facilities that are not subject to NSPS OOOOb may conduct LDAR for state, federal, or voluntary programs and may wish to screen pneumatic controllers while on-site and use that empirical observation of properly functioning or malfunctioning for GHGRP reporting.

While many of these regulatory programs would meet the technology options provided in 98.234(a) for use in monitoring properly functioning pneumatic devices, additional flexibility should be incorporated by allowing the use of AVO. AVO is appropriate because AVO inspections can be used to detect that an intermittent device is continuously venting through feeling the gas exit port, as previously stated.

3.1.5 EPA Has Underestimated the Cost of Direct Measurement for Pneumatic Devices

Oil and gas companies do not currently own or have training to conduct direct measurement of pneumatic devices. EPA included no additional cost for purchasing the high flow sampling equipment, staff or training on the equipment. With the large number of operators having to acquire this data at the same time, new equipment must be first manufactured and then purchased by these operators to do this work concurrently. EPA added no additional labor impact; it will require significantly more staff to conduct the measurements. The company will need to hire staff, as additional staff will be needed to conduct these measurements that require 15 minutes per measurement minimum over a range of device counts per facility depending on whether it is a gas or oil well, number of wells, and the equipment required for production. It will likely not be possible to cover 5-10 sites per day, considering repairs will likely be performed at the same time and many sites and pneumatic devices will be spread out over long distances. Furthermore, operators will need to be trained to use high flow samplers as this equipment is currently not used in the oil and gas industry. None of these additional costs have been addressed in the Regulatory Impact Analysis. EPA claimed all this could be done with only an additional $600,714 in cost which would not be sufficient to cover the cost for a medium sized operator.

3.2 Acid Gas Removal and Nitrogen Removal Units

3.2.1 Proposed Methods for Methane Emissions

The proposed mass balance approach for quantifying emissions will not lead to accurate reporting for methane emissions, and sour gas sampling poses a significant safety concern.

EPA proposes to report methane along with CO_2 from Acid Gas Removal Units (AGRUs) and Nitrogen Removal Units (NRUs). The Industry Trades believe that the proposed methodology in Equation W-4C (a mass balance approach) will not lead to accurate reporting for methane emissions. Since the solubility of methane in amine is very low, the difference in methane concentration in the inlet and outlet processed gas stream will be negligible. Therefore, the ability to discern a difference in inlet versus outlet methane composition will make it difficult (if not impossible) to accurately determine methane emissions using a mass balance approach. Further, sampling the high-pressure acid gas stream at the inlet of the AGRU contactor poses a significant safety concern (see next comment). For these reasons, the Industry Trades recommend removing this methodology for methane emissions reporting.

EPA is proposing a requirement to perform direct sampling of gas streams into these units at least annually. The Industry Trades remind EPA that these streams can also contain dangerous levels of hydrogen sulfide (H_2S), and any work near or around these units that is not necessary for the optimal function of the equipment should be limited to protect the personnel responsible for performing these tasks. The Industry Trades recommend removing the prescriptive sampling requirements for these streams and allow reporters to use representative samples or direct site-specific samples if deemed to be appropriate.

For the simulation method (Method 4), the Industry Trades recommend that EPA clarify that representative measurements can be one time, annual or a more frequent measurement as deemed appropriate for the facility's operation.

3.2.2 Reporting Requirements for AGRUs and NRUs

Some of the proposed reporting requirements for AGRUs and NRUs are duplicative and unnecessary, so should be removed.

EPA proposes that those operators sending gas from an AGRU or NRU to a control device also report associated details regarding the combustion device (flare ID, gas flow rate, etc.). Requiring this information to be reported on this tab of the Subpart W reporting form could cause duplicative reporting with sources on other tabs (e.g., flares), and is ultimately not relevant to reporting by itself. The Industry Trades recommend removing this requirement. Reporting this level of detail is also inconsistent with EPA's 2022 proposed revisions, which greatly streamlined the reporting requirements for flares.

EPA is proposing to include solvent type in data reporting; the Industry Trades does not believe this information to be beneficial or helpful in validating the reported information, and EPA did not address why this element is to be reported in the TSD. The Industry Trades recommend that the EPA remove this unnecessary reporting requirement.

Finally, the Industry Trades request clarity from EPA around reporting activities such as acid gas injection through Subparts W, PP and UU. The proposed requirement to report CO_2 sent offsite under Subpart PP is duplicative of CO_2 supplier reporting. Regarding the WEC, it will be absolutely critical that industry has a clear understanding of exactly how emissions are to be accounted for between these subparts without over-reporting, double counting, or allowing some operators to not report under these subparts at all (creating an economic disadvantage as it is unclear how some activities which result in producing CO_2 are to be accounted for in the various rules).

3.3 Dehydrators

3.3.1 Desiccant Dehydrators

Reporting requirements for desiccant dehydrators should be streamlined for a source type that is not a significant contributor to GHG emissions.

In the late-2022 proposed changes, EPA appeared to be moving away from requiring detailed information reported for desiccant dehydrators; however, in the current proposal (August 1st, 2023), EPA is requiring more reporting details. Emissions from desiccant dehydrators are periodic and can be very infrequent in nature. The Industry Trades support reducing the overall reporting requirements on these units as they are not significant contributors to annual GHG emissions.

Molecular sieve dehydrator emissions are expected to be extremely infrequent (i.e., once every 5-10 years), and should be categorized as blowdown emissions.

EPA is also proposing to add molecular sieve units to the desiccant dehydrator category. Molecular sieves are closed systems with no emissions to the atmosphere, except when the desiccant must be changed which is infrequent; typically, only once every 5-10 years. Furthermore, emissions from opening a molecular sieve dehydrator would be an activity considered by most operators to be a blowdown event – and should be accounted for under the blowdown category rather than under dehydrators. Categorizing molecular sieves under the desiccant dehydrator category not only raises confusion but could potentially result in double counting of the blowdown emissions.

3.3.2 Proposed Measurement Data

The proposed measurement requirements are burdensome and will not increase the accuracy of the emissions estimates; therefore, engineering estimates for parameters should be allowed.

EPA is proposing to require direct measurement of some parameters for large dehydrators. Specifically, EPA is proposing to require direct measurement of the feed natural gas flow rate, feed natural gas water content, and wet natural gas temperature and pressure at the absorber inlet. The Industry Trades do not believe that direct measurement of these parameters is appropriate nor that it would result in more accurately reported emissions. Sampling the feed natural gas water content, gas temperature and pressure will provide an instantaneous snapshot view of the operational conditions of a unit that operates year-round, and in potentially varying operating conditions, during which these parameters may shift.

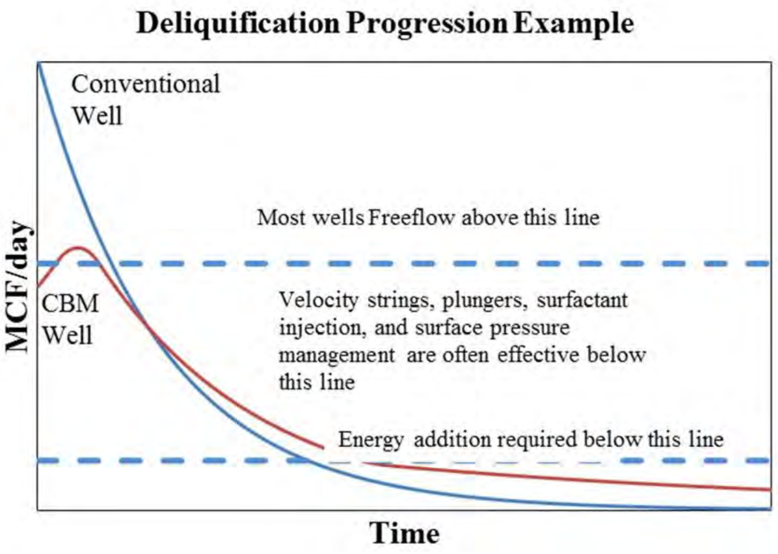
In some instances, facilities are not equipped with a meter upstream of the dehydration unit; instead, the gas is measured at the outlet of the facility. As a result, collecting direct measurement of feed natural gas flowrate will require extensive modifications without increasing the quality of the reported data. Dehydrator emissions are not directly proportional to natural gas throughput; in other words, the inlet gas rate to the dehydrator alone does not correlate with dehydrator emissions. Instead, glycol recirculation pump rate, configuration (e.g., flash tank separator, stripping gas) and operating pressures do impact emissions, and are known by operations in order to maintain optimum operating conditions. Requiring operators to install, calibrate and maintain meters at the inlet to the dehydrators would be costly while not addressing the accuracy of the elements that do meaningfully impact actual emissions. Therefore, the Industry Trades request that engineering estimates of the parameters used in the simulation software continue to be included as an option, especially considering the parameters represent annual averages.

3.4 Well Venting for Liquids Unloading

EPA should not require flow meter measurements of liquids unloading venting under Calculation Method 1 as it is technically and economically infeasible.

The proposed rule language that requires Calculation Method 1 every three years is unnecessary and burdensome and will not lead to more accurate reporting. EPA states in the preamble that this requirement will 'ensure that the engineering equations accurately and consistently represent the quantity of emissions from unloading event.' EPA must justify this additional burden and how potential differences between method results will be treated, as repeated validation of the methods will not lead to more accurate reporting. Further, EPA did not consider the Allen *et al* 2015 study that directly measured emissions from liquids unloading.[21]

Which wells will require and how often they require liquids unloading venting is not predictable or consistent. Liquids unloading or deliquification is the process of removing liquids build-up in a gas well. Not all deliquification techniques result in venting. Most wells in the US do not vent to the atmosphere. Managing well bore liquids build-up in gas wells is required to maintain production, avoid early abandonment of the wells, and maximize resource recovery. Liquids build up in the well when the velocity of the production string is not sufficient to push the liquids up the well bore. The deliquification approaches change as a well moves through its lifecycle, as shown in the figure below. Manually opening a well to atmosphere to reduce the back pressure on the liquids column results in most of the liquids unloading venting. When this is needed is variable and does not necessarily occur every 3 years.



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[21] https://pubs.acs.org/doi/10.1021/es504016r.

Adding a flow meter will put back pressure on the well, restricting flow and preventing the well from unloading or making it more difficult. The purpose of liquids unloading is to relieve the back pressure on the well so that the well is able to push liquids, and a flow meter would prevent this from occurring. Anecdotal evidence from one operator that currently unloads gas wells in Colorado has trialed measurement on liquids unloading on twelve wells indicating this. The operator found results similar to the current GHGRP calculations. Additionally, the operator found that to use a meter, the gas must be routed through a knockout or other vessel that may have small piping between it and the meter. The constriction made the unloads take longer and reduced the effectiveness of the unloads. Of the twelve trial measurements, not a single well successfully unloaded itself.

The volume of gas, and associated GHG emissions, is relatively low and therefore does not warrant the additional expense and effort of measurement. In fact, the total emissions reported in 2021 for all operators was a very small percentage of overall methane emissions from onshore production.

Measuring the small volume will be extremely challenging and likely require a costly ultrasonic meter (please see the flow meter challenges discussed in more detail in Section 3.8.13.8.1 of the comments). The measurements will be challenging to obtain, as they are short duration and turbulent flow; therefore, the low flow is unlikely to be measured by a flow meter.

The rule does not account for all the added costs of a flow meter that will likely not be capable of measuring the small volume of the gas. These costs include:

- The flow meter(s)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofit the line to add a flow meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expanding or adding the remote transmitting unit
- Calibration and maintenance of the flow meter
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

Additionally, EPA does not require operators under NSPS OOOOb to install a flow meter for liquids unloading venting. NSPS OOOOb does not prescribe these flow meter requirements as necessary to achieve the zero-emission limit for liquids unloading, or for the recordkeeping/reporting requirements for these events, so it is unclear why this would be required under Subpart W.

Furthermore, a meter could be installed on a well that had liquids unloading venting in a previous year and never does again, or not be installed on a well that suddenly requires liquids unloading venting.

Industry should be allowed to continue to use the liquid unloading engineering estimates or other engineering process knowledge to estimate the duration and volume of emissions as measurement will not result in more accurate estimates.

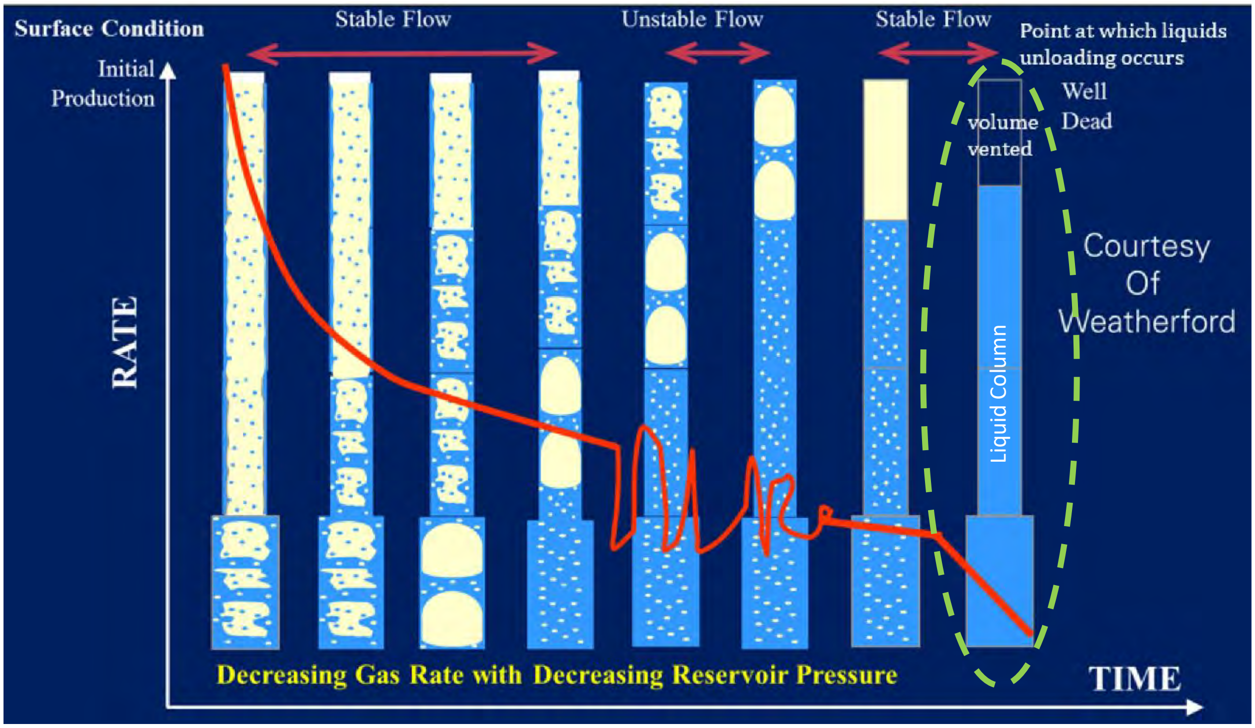
Additional suggested revisions will improve the clarity of the requirements for reporters.

EPA should clarify that liquids unloading only applies to gas wells as was done in NSPS OOOOb. Oil wells typically require artificial lift to produce the liquids and do not vent gas.

The Industry Trades support proposed revisions to add reporting requirements for liquids unloading events which vent directly to atmosphere or are routed to a control device, including whether the unloading event is automatic or manual, specific flow-line and tubing depth data, and the hours that wells are left open during unloading events. However, EPA should clarify that reporting for unloading events should only apply when the gas is vented directly to the atmosphere or routed to a control device. These additions will improve clarity for reporters and provide greater context for the reported emissions for EPA.

Additionally, EPA should consider revising the definition of CDp in Equation W-8 to Idp (Internal Diameter) to allow the application of either tubing diameter if the well is equipped with tubing string and no plunger lift, or casing diameter if the well does not have tubing and plunger lift. It is common practice for operators to first install a tubing string to increase flow velocity and install a plunger lift later when the well undergoes production decline. The diameter that is used in the equation should be the diameter of the portion of the well that is vented, whether venting the casing, tubing, or both. EPA should also clarify that the depth is based only on the vertical depth for horizontal wells.

Furthermore, the volume should be able to account for the fluid column depth. EPA should allow companies to determine the depth to the top of the fluid and exclude the remaining volume from the venting volume estimate. The reason for liquids unloading is to remove the liquid column from the well. The volume of liquid should not be considered gas that is vented, and rather only the depth above the fluids should be used to quantify the vented gas, as shown by the 'volume vented' in the following diagram.



3.5 Blowdowns

Streamline blowdown reporting to reduce the burden without affecting accuracy.

EPA is proposing to require site-level details regarding blowdowns. The Industry Trades recommend streamlining this source category by allowing reporters to aggregate events by type at each facility. Aggregating events by type would avoid line-by-line reporting per event and greatly reduce the complexity of reporting for the source category, without impacting data quality or transparency. For example, EPA should allow blowdown emissions to be reported by site, but aggregated by activity (i.e., all blowdown types would be reported in aggregate rather than line-by-line for each blowdown event).

For mid-field pipeline blowdowns not associated with a given well pad or gathering station, reporting a site could be challenging. The Industry Trades recommend allowing these types of blowdown events to be aggregated by county (without segment ID), which is consistent with other pipeline reporting under the current rules for Pipeline and Hazardous Materials Safety Administration (PHMSA).

As discussed in the 'Other Large Release Events' comments, there is a significant probability of double counting between blowdowns and 'Other Large Release Events' due to the low emission rate threshold proposed for the 'other large release events' source.

The Industry Trades are also concerned that, due to the low hourly emission rate threshold specified by EPA for the "Other Large Release Events" category, these events could be inadvertently counted in both this blowdown category as well as "Other Large Release Events" - resulting in significant double counting. EPA should clarify that any emission event that triggers the "Other Large Release Events" threshold but belongs under a reportable emissions source category (e.g., blowdowns) should be reported within its associated source category, not under "Other Large Release Events." The Industry Trades have elaborated on this point in the "Other Large Release Events" section of this letter.

3.6 Storage Tanks

3.6.1 Produced Water Tanks

Requiring estimation of emissions from produced water tanks is burdensome and unnecessary due to the low expected emissions of methane based on solubility limits.

Methane emissions from produced water tanks are expected to be low due to solubility limitations of methane in water. A study conducted by Idaho State University[22] to quantify the solubility of methane in produced water found that the solubility of methane was in a range between 1 and 12 scf/barrel at pressures ranging from around 100 to 2,000 psi and temperatures ranging from 200 to 300°F. While the study did not publish results for lower temperature ranges, the authors state that the solubility decreases with decreasing temperature and/or pressure. The solubility of methane in produced water is also expected to be lower in the presence of other hydrocarbon gases, such as ethane, per the study authors. The Idaho State University methane solubility study results are aligned with the produced water emission factors published in the 2021 API Compendium (Table 6-26): the Idaho State University study value at around 1000 psi, 200°F and 13 % salinity (4.2 scf/bbl.) equates to around 0.08 tonne CH_4/1,000 bbl which compares to 0.0536 tonne CH_4/1,000 bbl (at 1000 psi, 10% salinity) from Table 6-26 of the API Compendium. Since the methane emissions from a produced water tank would be lower than the

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[22] Blount, C. *et al*, *Solubility of Methane in Water Under Natural Conditions*, Idaho State University Department of Geology, June 1982, https://www.osti.gov/servlets/purl/5281520.

solubility limit (i.e., emissions are based on the partial pressure of methane in the tank headspace, which is lowered when other hydrocarbons are present), the Idaho State University study corroborates the API Compendium emission factors for produced water tanks.

If EPA opts to keep produced water tanks in the GHGRP, the Industry Trades recommend allowing operators to assume that water tanks contain 1% of the oil content. Texas Commission on Environmental Quality (TCEQ) Emissions Representation for Produced Water guidance[23] describes that oil or condensate floats on top of the water phase and contributes to the partial pressure within the tank. The Industry Trades recommend that EPA allow operators to assume that 1% of the oil content is in the produced water tanks which is a conservative estimation given that the guidance is intended to capture VOC emissions, and it is unlikely (as described above) that significant methane remains in the produced water.

The Industry Trades note that EPA provides a stuck dump valve emission factor for water tanks if method 1 or 2 is used, but no factor is provided for tanks using method 3.

3.6.2 Thief Hatches

EPA should allow improperly seated thief hatches to be treated as an "other" component under equipment leaks. The proposed capture efficiency of zero percent for storage tanks with an improperly seated thief hatch is inaccurate and would significantly overestimate emissions.

EPA has proposed a 100 percent reduction in VRU capture efficiency and flare destruction efficiency for both hydrocarbon and produced water storage tanks with open and improperly seated thief hatches. This proposed reduction in capture efficiency is inaccurate and would significantly overestimate methane emissions. The Industry Trades propose a bifurcated approach to reporting emissions from thief hatches where improperly seated thief hatches would be treated as a fugitive emission reported under equipment leaks, and open thief hatches would result in a zero percent capture efficiency for control devices.

Thief hatches are safety devices that relieve positive and negative pressure in atmospheric storage tanks to prevent structural damage. Thief hatches accomplish this by using weights or springs that allow the thief hatch valve to open at given pressure and vacuum settings. The thief hatch valve then reseats after the tank pressure or vacuum has dissipated. Thief hatch valves are designed to seat with minimal leakage under their pressure setting. For example, Enardo 660s, a common thief hatch in the upstream oil and gas industry, conforms to API 2000 Venting Atmospheric and Low-Pressure Storage Tanks Standard to not leak more than 5 SCFH at 75-90% of the thief hatch valve's pressure setpoint. Many of Enardo's valves can achieve smaller leak rates at 90% of the pressure setpoint. LaMot's L12 series thief hatches, another common type found at upstream oil and gas facilities, will not leak more than 1 SCFH at 90% of the pressure setpoint. These leak rates are a fraction of the gas produced in tanks. For example, the reduction in capture efficiency ranges from 0.5% to 2.5% given these leak rates for tanks with a relatively small throughput of 100 bbl./day and average GOR of 48 scfs/bbl given the above leak rates. Improperly seated thief hatches are technically closed but leak around the seat due to either grime on the valve gasket or an inadequate seal, similar to valves that leak into open-ended lines. Improperly seated thief hatches do not result in a zero percent capture efficiency because they are still able to

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[23] produced-water.pdf (texas.gov).

maintain positive pressure on the tanks, allowing gases to be routed to the control device. The leakage from an improperly seated thief hatch is significantly lower than from a partially open thief hatch.

EPA's proposal to assume zero percent capture efficiency from improperly seated thief hatches that are leaking as opposed to venting gas will grossly overstate methane emissions. Instead, the Industry Trades propose that improperly seated thief hatches be considered and reported as a fugitive emissions component (under the "other" fugitive component category).

A zero percent capture efficiency as proposed by EPA would be used for thief hatches that are observed above their setpoint using pressure transmitters and confirmed open or found open during inspections. The Industry Trades believe that this bifurcated approach of accounting for improperly seated thief hatches as equipment leaks, and assuming open thief hatches result in a zero percent capture efficiency would be a more accurate representation of emissions from thief hatches.

EPA should allow engineering estimates of the open thief hatch volumetric flow for tank batteries with a common vent line.

For many tank batteries, vent lines for multiple tanks are combined in a common vent line header that is routed to a control device. If one thief hatch is found open, the entire tank battery should not be assumed to have open thief hatches with a resultant zero percent capture efficiency. The Industry Trades suggest that EPA allow for use of engineering estimates, e.g., modeled volumes, in this case to report the emissions from the tank battery's open thief hatch.

EPA should allow other monitoring options to detect open thief hatches besides thief hatch sensors and visual inspections as visual inspections create significant safety concerns. The start date for an open thief hatch should be based on best available monitoring data.

EPA proposes thief hatch sensors or visual inspections as the monitoring options for detecting open thief hatches on controlled storage tanks. The Industry Trades recommend that EPA allows Tank Emission Monitoring Systems (TEMS) or other parametric monitoring in addition to thief hatch sensors. For example, many companies utilize a pressure transmitter or similar device to determine if a thief hatch is venting as they are more accurate.

Similarly, EPA should expand the visual inspections to allow other monitoring techniques (audio and olfactory in addition to visual, OGI, and alternative screening technology) due to potential safety issues with a strictly visual inspection of thief hatches. Since thief hatches are located on the top of the tanks, a visual inspection may require personnel to climb to the top of the tanks with potential vapor exposure (e.g., H_2S). Therefore, more remote monitoring techniques should be allowed to monitor for open thief hatches on controlled tanks.

Thief hatch sensors do periodically malfunction and may falsely indicate an open thief hatch. As such, EPA should allow reporters to exclude thief hatch sensor malfunction periods and instead use best available monitoring data (e.g., TEMS, other parametric monitoring, last inspection) when determining the time that the thief hatch was open in calculating and reporting storage tank emissions.

EPA is proposing that an open thief hatch without a thief hatch sensor is to be considered open since the last required inspection, which is proposed at least annually or more frequently if subject to AVO surveys under NSPS OOOOb or EG OOOOc. The Industry Trades recommend that EPA allow an operator to assume the thief hatch has been open since the last credible inspection (e.g., routine operator inspection) and not solely based on the last required thief hatch inspection. Proposed NSPS OOOOb and EG OOOOc (and earlier versions of the NSPS) do not require thief hatch sensors but instead require routine inspections of closed vent systems and covers for applicable storage vessels in addition to routine site surveys of fugitive emissions components. These inspections and additional monitoring would offer more frequent opportunities for operators to identify open thief hatches on a routine basis.

Emissions from an open thief hatch should be reported for the year in which it was discovered.

EPA is also seeking comment on expanding the start date of the open thief hatch prior to the beginning of the reporting year. The Industry Trades suggest that the reporting for an open thief hatch be limited to the calendar year in which the open thief hatch is discovered. If the thief hatch is open over a period that started prior to the start of the reporting year, then the total duration should be reported in the year in which it was discovered to avoid re-submittal of prior year reports. To expand on this point, the Industry Trades propose that any episodic GHG emissions be reported solely in the reporting year in which it was discovered.

3.6.3 Atmospheric Storage Tank Exclusions

The Industry Trades recommend that emergency use storage tanks and process tanks not be subject to reporting.

The Industry Trades also recommend that EPA specify that some tanks are not subject to reporting under this program. Some facilities contain tanks which are used only rarely for off spec oil and should be excluded from the definition of storage vessel. These process vessels are rated significantly higher than atmospheric and do not have similar venting risks as atmospheric storage tanks. The expected GHG emissions from these emergency use storage tanks would be minimal. At the state level, emergency use tanks are exempt from control requirements from state and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.[24,25]

Likewise, process tanks like those that recirculate liquids for processing should also be excluded. Storage tank regulations, including proposed NSPS OOOOb and EG OOOOc, have historically excluded process vessels or tanks. In short, any tank which is not expressly used as a primary storage vessel for hydrocarbon liquids and produced water (if included as proposed) in the normal operation of a production or gathering and boosting facility should be excluded. Therefore, the Industry Trades offer the following redline of the proposed definition of atmospheric pressure storage tank:

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[24] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[25] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

> *Atmospheric pressure storage tank means a vessel ~~(excluding sumps)~~ operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of nonearthen materials (e.g., wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof. For the purposes of this subpart, the following are not considered atmospheric pressure storage tanks:*
>
> - *Sumps;*
> - *Process vessels such as surge control vessels, bottoms receivers or knockout vessels; and*
> - *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

3.6.4 Gas-liquid Separator Liquid Dump Valves

The start date for a stuck separator dump valve should be based on best available monitoring data.

Like the above comment on open thief hatch monitoring, EPA should allow the start date for a stuck gas-liquid separator liquid dump valve to be based on the best monitoring data available (TEMS, other parametric monitoring, alternative screening technology, routine operator inspections, etc.) rather than solely the date of the last required annual visual dump valve inspection. This flexibility will allow operators to calculate storage tank emissions more accurately.

3.6.5 Addressing EPA's Request for Comments

Industry Trades recommend adding GOR analyses as an allowable calculation methodology.

EPA is seeking comments on whether adding a laboratory measurement of the GOR from a pressurized liquid sample is an appropriate calculation methodology for atmospheric storage tanks. The Industry Trades are supportive of adding this GOR method to calculate emissions from storage tanks and emphasize that these samples do not need to be taken on a site-by-site basis to be representative.

3.7 Associated Gas Venting and Flaring

EPA is proposing to require reporting of associated gas venting and flaring on a site-by-site basis. The Industry Trades recommend that EPA keep emissions and associated data rolled up to the basin-level (or county-level, as required by other regulatory programs, such as PHMSA).

EPA is seeking comment on whether to continue to require reporting of GOR, produced oil volume, gas to sales volume, etc. The Industry Trades are in support of no longer requiring these reporting elements, unless required by the WEC. In general, the Industry Trades support efforts to streamline the data reporting process, particularly when the reported elements are not used to calculate emissions.

3.8 Flares

It is critical to the Industry Trades that the GHGRP does not directly include monitoring, measuring and sampling requirements for flares in order to avoid conflicting or duplicative requirements. Instead, the GHGRP should refer to data available through other applicable federal air quality regulatory programs. The Industry Trades request that EPA should ensure consistency across programs. This will help ensure that the requirements in the GHGRP are fully harmonized with any potential requirements under other federal air quality programs.

The Industry Trades support more accurate approaches for destruction efficiency for estimating flare emissions; however, the **tiers as proposed should be amended** (specific comments below). Further, while it is sensible to allow for the use of available empirical data and appropriate to define multiple estimation methods based on different types of available information, **monitoring requirements that are repeated in Subpart W rather than referencing the applicable regulation, especially those that exceed NSPS OOOOb and EG OOOOc requirements, which are defined in those rules, should not be included in Subpart W**. Further, flare estimating methods should be appropriate to the equipment and designs deployed within the segment (e.g., small, mostly unassisted, distributed flares) rather than arbitrarily under a rubric designed for a specific compliance assurance matter from a very different set of facilities and designs (refining and chemical manufacturing). Finally, flared emissions should be reported at the facility level rather than at the individual well pad or site, and especially not with attribution to the flare gas source.

With the Industry Trade's recommendations, the Industry Trades generally support EPA's focus on pilot flame monitoring as unlit flares can be large sources of methane emissions from flares. However, the proposed rule's requirements to continuously measure or monitor flow volumes, as well as use continuous gas analyzers or pull quarterly samples for gas compositions would result in little benefit to accuracy while posing significant costs and safety risks. Further, the Industry Trades disagree with EPA's proposed three-tier destruction efficiency (see Comment under Section 3.8.4 below).

3.8.1 Flow Measurement

3.8.1.1 EPA Should Continue to Allow Process Simulation and Engineering Calculations for Flare Flow Volumes

The Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices. The proposed flare metering requirements are infeasible, burdensome and may lead to inaccuracies for most flares in production and gathering and boosting operations. Furthermore, EPA did not address the need to measure flare flow in the proposed rule's TSD. Likewise, the proposed parametric monitoring does not provide a more accurate or cost-effective alternative to metering. **EPA should retain the current Subpart W language stating that, "…If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data."**[26]

Proposed Flare Measurement Methods are Inaccurate and Infeasible for Low Pressure Flares

The proposed flare flow measurement methods are inaccurate, as well as infeasible, for low pressure flares in production and gathering and boosting operations.

The primary streams that are routed to flare at typical oil and gas facilities include:

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[26] Current § 98.233(n)(1)

- Low-flow pilot, purge, sweep, and/or auxiliary gas used to ensure flares are lit, operating safely, and have optimal destruction efficiencies;
- Low- pressure gas that is intermittent and turbulent from tank flashing, working, and breathing losses;
- Mid- pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales that has intermittent and turbulent flow; and
- High pressure separator gas flaring in areas with stranded gas pipeline take-away loss that has intermittent flow and is decreasing across the country.

Most meters are unable to accurately measure the flow of low-volume, low-pressure, intermittent, and turbulent streams.

In addition to the concerns surrounding the metering of each individual stream, the Industry Trades are concerned with EPA's application of flow meters or parametric monitoring across every upstream application. EPA's requirement to use continuous flow measurement devices or parametric monitoring for low-pressure flares and purge/sweep/auxiliary gas streams is technically infeasible. Meters require steady pressure and flow to accurately measure flow rates. Most meters are unable to accurately measure low pressure and flow conditions found in purge/sweep/auxiliary gas and storage tank streams, or variable flows affecting several streams, such as tanks due to production slugs or when separators dump fluids, sporadic flaring of associated natural gas, and high-pressure equipment blowdowns. Furthermore, the flare volumes rapidly decline from the initial production of the well and become more sporadic. Metering the scenarios described is challenging, and industry needs a flexible array of options to ensure proper combustion and accurate reporting. The incorrect application of meters or parametric monitoring devices can lead to inaccurate flare volumes relative to using process simulations, engineering estimates, and indirect measurement allowed under the current rule. **The Industry Trades recommend the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.** The industry utilizes reliable process simulation and engineering calculations which are often more accurate than metering low pressure, low flow, and highly variable streams within the upstream oil and gas industry. The Agency and industry rely on process simulation and engineering calculations in permitting, designing and maintaining facilities for safety and environmental reasons, and have made great strides in the accuracy of these approaches in recent decades. Additionally, the GHGRP allows process simulation to estimate composition and volume of gas for emissions (e.g., tank flash gas, dehydrators, etc.) that are not going to flare so the same methods should be allowed for gas streams that do go to flare. As such, it does not make sense to expend significant capital and operational resources to install continuous monitoring when engineering estimates are more reliable and allowed for uncontrolled sources (e.g., storage tank vents and dehydrators). Interestingly, EPA couples burdensome, although potentially less accurate, measurement technology for flow with default destruction efficiencies, without allowance for measurement or performance test data; this would negate any possible improvements in flare emissions accuracy.

In Colorado, the Air Pollution Control Division (APCD) recognized that flow meters have low accuracy at low vapor volumes by first approving a variance in 2022 to their flow meter requirements and more recently amending their Regulation 7 rule language in 2023 to include pressure actuators as an alternative to flow meters. Pressure actuators are an example of a solution implemented to ensure combustion. For reporting purposes, engineering estimates and simulation software based on site specific information (e.g., GOR and liquid throughput) are more accurate to generate emissions reporting information for flares in the production and gathering and boosting operations. It is important that the EPA understands that proper combustion and accurate reporting go hand in hand and should be viewed holistically so that operators are efficiently managing both concerns.

Meters available in the market and widely used in upstream oil and gas applications include differential pressure meters (e.g., orifice plate and v-cones), thermal mass meters, and ultrasonic meters. Differential pressure meters work by measuring the upstream and downstream pressure from a plate or cone with an orifice that allows gas to pass through. The amount of differential pressure can be increased or decreased for any given flow rate by selecting plates or cones with smaller and larger orifices. The flow of the gas passing through the meter can be inferred by the differential pressure between both points. The ratio of minimum and maximum capacities of meters, known as the turndown ratio, typically should not exceed 4:1 for differential pressure. This causes three primary considerations for differential pressure meters: first, they are inaccurate in low-pressure conditions; second, they are unable to accurately measure variable flow rates given their relatively tight turndown ratio (Zhang & Wang, 2021);[27] and lastly, they are sensitive to liquid and debris clogging the orifice causing an artificial increase in differential pressure and inaccurate high flow volume measurements. The relationship between low-pressure conditions, tight turndowns, and sensitivity to operating conditions is exacerbated by the fact that smaller orifices must be selected for lower pressures, causing even tighter turndown ratios that are more inaccurate with variable rates, and increasing the likelihood of clogging. Orifices can also become blown out by sudden increases in flow volume or debris, which causes a decrease in differential pressure and inaccurate low flow volume measurements. This makes differential pressure meters technically infeasible to measure purge, sweep and auxiliary gas lines that operate at low pressures, tank vent lines that operate at near atmospheric conditions, and high-pressure gas lines that are more variable than the turndown ratio of these meters.

Thermal mass meters operate on the principle of thermal dispersion, which states that the amount of heat absorbed by a fluid is proportional to its mass flow. These meters work by either comparing heat loss between two elements, or by measuring the amount of energy that must be expended to heat gas to a certain setpoint. Similar to differential pressure meters, thermal mass meters cannot accurately detect lower flow rates due to the unmeasurably small differences in temperature between the two elements or energy required to heat gas for low flow volumes. As noted in Kerr-McGee's letter to Colorado Department of Public Health & Environment Air Pollution Control Division (APCD) dated April 12th, 2022[28], the turndown ratio of thermal mass meters is typically 33:1, which means the meter is unreliable until 3% of the meter's maximum flowrate of 1,180 thousand standard cubic feet per day (MCFD) is achieved. Additional information regarding this comment can be found in Annex C of this letter. This also makes thermal mass meters technically infeasible to measure pilot/purge gas lines and tank vent lines as these streams do not meet the minimum flowrates required for thermal mass meters due to their low rates and declining production over time. In addition to issues with low flow rates, thermal mass meters are highly susceptible to entrained mist, liquid, or particles that can affect the

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[27] Zhang, Y and Wang, J. *Review of metering and gas measurements in high-volume shale gas wells*, Journal of Petroleum Exploration and Production Technology, 12:1561-1594, December 2021, https://doi.org/10.1007/s13202-021-01395-9.

[28] APCD-PHS-EX-035.

thermal properties of the gas being measured (API, 2021).[29] For example, the specific heat capacity of propane increases from 1.67 kJ/Kg-K in the gaseous phase to 2.4 kJ/Kg-K in the liquid phase. Thermal mass meters can measure dry gas in steady flow conditions above their minimum capacity, which makes them suitable for select flare scenarios depending on facility design and process. However, they do not have the level of accuracy required to form any basis for the methane fee.

Ultrasonic meters operate on the principle of doppler shift by measuring the time it takes for sound to travel from an ultrasonic signal transmitter to a receiver upstream and downstream of gas flow. Generally, ultrasonic meters do not work well in low flow conditions because of the unmeasurably small doppler shift that occurs at lower velocities. Thus, they are technically infeasible to accurately measure low pressure pilot/purge gas and storage tank streams. They are also sensitive to mist, liquids, or particulates that may block the receiver from receiving the ultrasonic signal, but not as much as differential pressure or thermal mass meters. They are also sensitive to surrounding equipment that may produce vibrations or sounds near the same frequency as the ultrasonic signal. For more information, refer to *API Manual of Petroleum Measurement Standards*, Chapter 14.10.[30]

It is important to note that meters can only be used when facilities have a dedicated high-pressure flare as opposed to a single control device (i.e., a flare that controls tanks, associated natural gas (ANG), and potentially other sources). Ultrasonic meters are also economically infeasible given they can cost $20,000 to $30,000 each to purchase, and additional capital required for installation and labor. API commented on this in our comments on NSPS OOOOb and EG OOOOc Supplemental Proposal, submitted on February 13, 2023, and included in Annex C of this letter. Furthermore, this does not include the cost to install SCADA communications systems that can cost up to $100,000 per facility for unconnected remote locations.

Proposed Parametric Monitoring Does Not Provide a More Accurate Alternative

The proposed alternative of parametric monitoring does not provide a more accurate or cost-effective alternative to metering.

Based on operator experience, field testing programs comparing parametric monitoring and metered flare volumes have shown that parametric monitoring over-estimates flow volumes. Implementing parametric monitoring to estimate flow is complex and requires detailed data on the appropriate flow orifice diameter, installing additional instrumentation to monitor temperature and pressure difference across the orifice, as well as the need to install SCADA communication systems at remote locations and analytical software to estimate flow rate. The requirement to either install meters or parametric monitoring systems is burdensome and unnecessary considering that the main contribution to GHG emissions from flaring is unlit flares, which are addressed separately in the proposed rule.

For all the reasons stated above, **the Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations** that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.

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[29] American Petroleum Institute (API), *Manual of Petroleum Measurement Standards, Chapter 14.10, Natural Gas Fluids Measurement – Measurement of Flow to Flares*, Second Edition, December 2021.

[30] Ibid.

3.8.1.2 *Proposed Flare Flow Measurement and Monitoring Requirements are Overly Burdensome*

The cost and burden associated with measuring every stream is significant and understated by EPA.

Continuously measuring flow volumes or utilizing parametric monitoring devices for each source that routes gas to a flare will be extremely burdensome while failing to result in more accurate emissions reporting. Many operators have thousands of flares that would be affected, requiring either new meters or parametric monitoring devices. The majority of flares would require at least two gas streams to be monitored - the main vent line or "waste gas" stream and the purge/sweep/auxiliary gas stream. The cost and burden impact of monitoring – at a minimum – must include:

- Minimum of 2 or more specialized meters, or parametric monitoring systems
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the run for the meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expending or adding the remote transmitting unit
- Calibration and maintenance
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

The capital and operational costs to continuously monitor flare volumes using meters or parametric monitoring devices, as proposed, would result in significant costs to reporters that were not adequately addressed in the proposed rule's burden assessment. EPA did not explain the cost estimates in Table A-3 of "Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," and we note that significant contributions to cost and burden were likely not included in the analysis based upon the magnitude of the estimate. As important, however, is the unjustified acceleration of installation of equipment that is already anticipated over the course of the next few years.

Paradoxically, this increased capital and operational cost can lead to flare volumes becoming less accurate than using the methodology under the current rule, as described below.

The requirement to continuously monitor at least two streams for thousands of flares at remote locations across the upstream oil and gas industry would require significant capital and operational expenditure with little benefit given the legitimate concerns regarding meter accuracy. As noted above, continuous monitoring flare flow volume would require costly specialized meters. As such, the Industry Trades believe EPA has underestimated the capital cost burden for purchase and installation of continuous parameter monitoring systems. The Industry Trades provided the Office of Management and Budget (OMB) this comment in response to Docket ID EPA-HQ-OAR-2023-0234.

3.8.1.3 Proposed Timeline for Flow Measurement or Monitoring is Unrealistic

If EPA does not continue to allow process simulation and engineering calculation for flare flow volumes, we are concerned about EPA's proposed requirements to expedite the installation of additional continuous monitoring systems on flares.

The deployment of new continuous metering or parametric monitoring equipment can pose significant challenges. This is particularly true for extensive oil and natural gas production sites and midstream assets, as they often lack SCADA systems or comparable infrastructure. This deficiency limits the connectivity of in-field instrumentation and access to a data historian. Additionally, the absence of necessary infrastructure, such as electricity and data infrastructure including Wi-Fi and even cellular coverage, further diminishes any cost-effective means for installing new instruments.

Existing supply chain delays would only be exacerbated by requiring flow meters on flares as proposed. Operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for flow meters; these timelines are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. These timelines account only for supply chain delays and do not contemplate the additional time needed to install equipment. These supply chain challenges for flow meters and other equipment were documented in a blinded operator survey submitted to EPA on September 20th (and included in Annex E of this letter).

As noted in API's previous comments on NSPS OOOOb and EG OOOOc:[31] "In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk. Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap." Like the supply chain delays, finalization of NSPS OOOOb and the potential need for flow meters under Subpart W would only exacerbate current installation timelines. Instead of requiring all flare stack emissions to install flow measurement by January 1, 2025 (less than 18 months between the proposed rule and the applicability date and likely less than 12 months from final rule) the proposed revisions should allow operators to transition to measurement data as it becomes available through the implementation of NSPS OOOOb or EG OOOOc, which will incorporate practicable implementation schedules for monitoring requirements.

3.8.2 Pilot Flame Monitoring

The Industry Trades generally agree that it is more appropriate to identify discrete periods where flares are unlit for the purposes of estimating emissions that go un-combusted; however, several revisions should be made to the specific requirements:

1. **Double counting of emissions during periods of time when the flare is unlit should be avoided.** Because operators will identify discrete periods of time where the flare is operating with 0% combustion efficiency and report emissions accordingly, this volume of emissions should not be included in destruction/combustion efficiency (more in section 3.8.4 below).

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[31] Comment 5.2. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428

2. Monitoring for the presence of a pilot flame or combustion flame using a device capable of detecting that the pilot or combustion flare is present should **only be required for periods of time where there is flow of regulated material** going to the flare rather than "at all times."
   (i) It is illogical to track the length of time a flare is both unlit and there is zero flow because it has no impact on the estimated emissions.
   (ii) Additionally, automatic ignition systems have been deployed many operators and include a flame monitoring device. Since these devices include a flame monitoring device, they would satisfy the obligation, where EPA affirms the requirements for monitoring only apply during periods of flare flow. To reduce emissions or in areas where supplemental gas is needed because the well does not produce gas or enough gas, many operators are installing automatic ignition systems that activate when flow to the flare is detected instead of maintaining a continuous pilot flame. By design, an automatic ignition system will be unlit during periods with no detectable flow to the flare or the valve to the flare is closed. Some state rules, such as in New Mexico and Texas, allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).
3. **Additional monitoring flexibility will improve accuracy of reporting and should be afforded to the pilot monitoring**. The Industry Trades recommend either removing the sentence in 40 CFR 98.233(n)(2), stating "if you continuously monitor, then periods when the flare are unlit must be determined based on those data" or revising it to allow redundant and/or additional parametric monitoring or visual inspection to be used. This is because monitoring device malfunctions are not uncommon for thermocouples (or equivalent devices) resulting in false readings; however, other monitored parameters can confirm that the pilot is, indeed, lit even if the monitoring device errantly indicates the pilot is unlit. For example, operators that have flares with multiple thermocouples to monitor flame temperature report that the readings can be widely variable and have observed that the presence of a flame can be indicated by a single thermocouple within the installed group. There are also cases where a pilot has malfunctioned, but visual inspection using site visits or cameras on location reveal a robustly lit combustion flame. In extreme weather conditions, such as in Alaska, Wyoming, or North Dakota, the thermocouple reading will be affected by the ambient temperature and wind conditions. So, where a monitoring device indicates the absence of a pilot flame or combustion flame, an operator should have the option to confirm that finding through other means and eliminate that period from the log of time in which the flare is unlit if supported by other data.
4. As an alternative to thermocouple monitoring, the Industry Trades recommend that visual inspections can be performed using cameras on location.

The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).

3.8.3 Gas Composition Requirements

Similar to the discussion regarding requirements for flow monitoring in this letter, the Industry Trades **urge EPA to retain the option "to use the appropriate gas composition for each stream of hydrocarbons going to the flare" in the absence of a continuous composition analyzer.** The proposed requirements to either use a continuous composition analyzer or take quarterly samples are both unnecessary (source flow composition is relatively stable at oil and gas facilities) and potentially conflict with the specific requirements and implementation timing of compliance assurance requirements in NSPS OOOOb and EG OOOOc.

EPA should provide an option to use process models for flared gas, which is how most compositions are currently being determined and with reasonable accuracy.

The proposed requirements to measure or sample the gas composition for each flare are economically and technically infeasible, and engineering estimates and representative analysis should be allowed.

EPA's requirement that quarterly gas samples be pulled for each stream that goes to flare has no basis and was not addressed in the proposed rule's TSD. The proposed requirement to install a continuous gas analyzer or take quarterly samples of the inlet gas to every flare is unreasonable and burdensome for several reasons.

1. **The gas composition is relatively stable over time rendering more frequent characterization of low value**. Flare gas composition in oil and gas operations is relatively stable and will not change significantly over time. As discussed above, the primary streams going to flare at typical oil and gas facilities include:
    - Pilot, purge, sweep, and/or auxiliary gas;
    - Low-pressure gas from tank flash, working, and breathing losses;
    - Mid-pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales; and
    - High-pressure separator flaring in areas with stranded gas pipeline take-away loss which is intermittent and decreasing across the country.[32,33]

    EPA also recognized that the gas composition could be stable by proposing an alternate net heating value demonstration in NSPS OOOOb and EG OOOOc[34]. While Industry Trades commented that this demonstration should be simplified due to the relatively stable and generally sufficient heating value of the gas streams, its inclusion in the compliance assurance requirements of NSPS OOOOb and EG OOOOc recognizes that the gas streams could be demonstrated to be stable.

2. **EPA has not justified the costs related to the installation of continuous composition analyzers or quarterly sampling, and go beyond NSPS OOOOb and EGOOOOc compliance assurance requirements**. Installation of a continuous monitor for each stream or quarterly sampling will be

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[32] https://www.api.org/news-policy-and-issues/blog/2022/05/24/reports-us-among-world-leaders-in-reducing-flaring.

[33] https://www.hartenergy.com/exclusives/us-reduces-flaring-and-flaring-intensity-world-bank-says-204724.

[34] Proposed § 60.5417b(d)(1)(viii)(C)(1) to (5).

extremely costly for installation, data gathering and management, calibration and maintenance or sampling and analysis for the thousands of flares impacted. Costs for continuous monitors include:

- Monitor(s) (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the continuous analyzer
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expending or adding the remote transmitting unit
- Calibration and maintenance of the monitor
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

For quarterly sampling, the associated costs include:

- Minimum of 2 sample ports (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting of the flare line for the sample ports
- Cost of gathering the samples each quarter
- Cost of analyzing the samples every quarter
- Data management system
- Data review and analytics
- Data entry for calculations

Flare systems in upstream operations are not designed for sampling, meaning that physical modifications to install sampling ports would be required to enable samples to be taken, which is costly and not always technically feasible. Also, installing sampling ports, meters/instrumentation, or continuous gas analyzers would require production to be shut down, which would be logistically challenging and generally result in flaring to accommodate causing more emissions.

As noted in API's comments on NSPS OOOOb:[35] "Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000." The estimated cost per gas sample was "$1,500 to $2,000 including shipping and analysis." Therefore, the annual cost for quarterly sampling could easily exceed $10 million for an operator considering 4 samples per year per stream, at least 2 streams per site, and a thousand or more sites to sample annually.

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[35] Comment 5.6.4. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.

Finally, a continuous compositional monitor or quarterly sampling goes beyond the continuous net heating value (NHV) monitoring or NHV demonstration required under proposed NSPS OOOOb and EG OOOOc. As stated at the beginning of this section, Subpart W must not impose monitoring requirements beyond other applicable regulations. While a continuous compositional monitor could be used for NHV monitoring, compositional analyzers (e.g., gas chromatographs) are more expensive than NHV monitoring devices (e.g., calorimeters). Given the relatively stable composition of gas streams and cost for compositional monitoring, Subpart W should simply reference NSPS OOOOb and EG OOOOc monitoring requirement as they relate to methane destruction efficiency (see comments bellow) and not impose additional composition monitoring requirements.

3.8.3.1 Supply Chain Constraints

As noted above for flow meters, operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for monitoring equipment for flares; these delays are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. Requiring compositional monitoring under Subpart W would further exacerbate the existing supply chain constraints with minimal benefit to reported GHG emissions.

3.8.3.2 Technical Feasibility Issues

Additionally, it is technically infeasible to pull gas samples from low pressure flares. A positive pressure is required to pull gas samples from flare lines. Low pressure flare vent lines operate at near atmospheric conditions, which would either take hours to collect a large enough sample (i.e., fill a bag with enough gas) to send to laboratory for analysis or require a gas chromatograph equipped with a pump to be brought on location. Requiring a gas chromatograph to pull quarterly gas samples is economically infeasible.. Process simulation would be a more accurate representation of tank gas. It would be equally difficult to pull samples for mid- and high-pressure flaring given the intermittent nature of these events. A more accurate representation of high-pressure gas composition, as well as pilot/purge gas, would be sales gas composition which is ultimately what is being combusted at the flare. Finally, as stated above, EPA does not address why this frequency in sampling is being proposed in either the Technical Support Document or the preamble.

3.8.4 Variable 'Combustion Efficiency' Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

3.8.4.1 NESHAP CC Requirements Are Not Applicable to Subpart W Flares

The reference to and requirements from refinery NESHAP CC are not applicable for Tier 1 reporting under Subpart W.

EPA should remove any tier requirement related to NESHAP CC for refineries because the characteristics of the flare designs, operating conditions, and composition variability are not representative of, and in fact quite dissimilar from, petroleum and natural gas systems flares.

The Industry Trades believe the reference to NESHAP CC which applies to petroleum refineries is inappropriate. There are numerous ways in which refinery and chemical manufacturing flares and flare gas differ from that of upstream and midstream.

- Flare gas composition and flows span large ranges: Refinery flares receive flare gas of highly variable composition and of varying levels of heat content. Refinery flares can be dedicated to one or more related process units but are quite often very large and in service to many different process units, or even operate as a single interconnected system. Resultantly, the range of flows and composition to the flare is highly variable over a matter of hours. The heating value of the streams is typically much higher in upstream and midstream with the high-pressure gas being primarily natural gas and the gas from secondary separators, heater treaters and vapor recovery towers having a higher heating value greater than 2000 btu/scf. Except for the minority of wells that produce inert gases, where the composition of that production is known, flare gas streams are always highly combustible.
- Because refinery and petrochemical manufacturing flares combust gases with greater propensity to produce smoke (e.g., concentrations of olefins, diolefins, and aromatics) and thus are generally designed with an emphasis on smoke control, often including one or more steam addition systems, there is a documented risk of “over-steaming” for these flares. Less frequently, refinery and chemical manufacturing flares are air assisted, and even more rarely, unassisted. The reverse trend is true for upstream and midstream flares, where steam assist is the exception to the norm. Utilities to support steam assist are generally not available, upstream flares are less likely to need commensurate smoke suppression systems, and upstream and midstream flares are much smaller and dedicated units.
- While upstream operations are also actively seeking to reduce flaring, Refinery and chemical manufacturing flares also often have an obligation to flare gas minimization. Accordingly, any routine flaring that exceeds the flare gas recovery capacity of the facility results in flaring at extremely high turn-down conditions for the flare. High turn-down (<0.1% of flare capacity) at a steam-assisted flares presented the perfect storm for degraded combustion efficiency, which drove the enforcement initiative, subsequent ICR testing, and ultimately rulemaking to address this specific conditions. This condition does not exist in the up- and midstream segments.

3.8.4.2 EPA Should Allow Direct Measurement and Performance Testing for Flare Methane Destruction Efficiency

Direct measurement and performance testing by manufacturers or operators should be accepted as an optional demonstration of even greater destruction efficiency beyond 98%.

The Industry Trades request that EPA allow directly measured data, as well as NSPS performance testing by manufacturers or operators, as a more accurate approach to quantify an individual flare’s methane destruction efficiency. Whether or not a flare is monitored pursuant to NESHAP CC or NSPS OOOOb has no actual bearing on the flare combustion efficiency values. Even if a flare meets the monitoring requirements of either rule, it does not necessarily follow that the actual flare combustion efficiency is at the respective values. For example, flow volume values may indicate flow exceeding minimum or maximum flows which is an indicator of potential suboptimal combustion efficiency. Additionally, if all monitored flare values are within performance standards, the flare combustion efficiency could be higher than the specified combustion efficiency for the specified tier. As is standard practice with GHG estimation methodologies, the timing and values of detections, measurements, and parametric data—not whether monitoring requirements are met--determine emission rates, such as flare combustion efficiency. Thus, the Industry Trades recommend that EPA supplement the tiered monitoring approach to flare combustion efficiency reporting to include directly measured data or NSPS performance testing by manufacturers or operators.

Some operators are deploying emergent technologies to directly measure combustion efficiency (or the closely related destruction efficiency) for flares, such as Providence Photonics Mantis and Mantis light (additional information regarding this technology is available in Annex D). Many operators, either through state or permit requirements, or voluntarily, conduct more traditional stack testing to assure high combustion efficiency of enclosed combustors, which also meet the definition of "flare" in Subpart W. Both of those testing methodologies provide the most accurate estimate of any particular flare and should be allowed as an option.

EPA should also allow for the use of the recently finalized "Other Test Method (OTM 52): *Method for Determination of Combustion Efficiency from Enclosed Combustion Devices Located at Oil and Gas Facilities*,"[36] using Portable Analyzers to determine destruction or combustion efficiency.

These approaches would further support technology development and allow for flexibility in using advanced and evolving technologies. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program (REMEDY | arpa-e.energy.gov) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in flares. If technology development from this 3-year, $35 million research program is successful, the ability to use a higher flaring efficiency value in methane emissions reporting could help to drive greater adoption of new technologies in operations.

3.8.4.3 Requirements for Proposed Tier 2 Support 98% Methane Destruction Efficiency

The compliance assurance provisions in NSPS OOOOb and EG OOOOc, as proposed under Tier 2, are sufficient to ensure 98% methane destruction efficiency.

The underlying goals of the flare compliance assurance provisions in part 63 subpart CC flare requirements was to supplement the provisions in 60.18 to specifically protect against over steaming, especially in concert with lower heat content flare gas by transitioning the compliance point from heat content of flare gas to heat content reaching the combustion zone, which would account for inert gases introduced to the flare gas within the variable gas composition in manufacturing settings, and account for the impact of steam on the combustion zone. In the absence of those conditions, 60.18 provisions continue to provide a reasonable assurance of high combustion efficiency.

Further, a recent study on flare destruction and removal efficiency (DRE) conducted in the Permian Basin by members of the Industry Trades indicates that over 85% of flares have a destruction efficiency above 98% (refer to comment below in Section 3.8.4.4). Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. These findings support a 98% combustion efficiency default for Tier 2, especially considering the enhanced monitoring requirements aligned with NSPS OOOOb rule requirements.

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[36] https://www.epa.gov/system/files/documents/2023-09/otm-52_method-for-determination-of-combustion-efficiency-from-enclosed-combustors_clean_8_31_2023-004.pdf.

3.8.4.4 Tier 3 Methane Destruction Efficiency Should be Revised to a Minimum of 95%

Destruction Efficiency of 95% Supported by Plant *et al* Study

The default proposed 'combustion efficiency' in Tier 3 reporting is based upon errant analysis in the Plant *et al* study and a more appropriate interpretation of those data would result in an overall methane destruction efficiency of >95% across upstream and gathering and boosting flares.

The Plant *et al* published study results state that 'the majority of flares function close to expected performance, with DRE values near 98%.'[37] The study concluded that approximately **95% methane destruction efficiency was the average across the basins in the study without accounting for unlit flares**. Since Subpart W already requires the monitoring of and segregation of periods where flares are unlit, it is not appropriate to *also* include that condition in an average destruction efficiency assumption. The average observed DRE across the three regions of study is 95.2% and the average total effective DRE after accounting for unlit flares is 91.1%.[38] The lower 'combustion efficiency' proposed by EPA is not aligned with the methane destruction efficiency findings from the Plant *et al* study, and represents the inclusion of unlit flares, **meaning that the unlit flare contribution would effectively be double counted since unlit flares are reported separately.** Therefore, 95% methane destruction efficiency would be more appropriate for Tier 3 as supported by the study referenced by EPA (rather than 92%). This 95% destruction efficiency would be aligned with NSPS OOOO and OOOOa control requirements; requiring a Tier 3 efficiency of 92% would not be aligned with other applicable requirements.

Furthermore, in the Plant *et al* study, investigators did not have access to operational data, including flow information, for any of the observed flares. Resultantly, extrapolation of the observations to a regional emission factor inherently assumes that the set of flares observed well represented the population of flares in terms of size, design, and most importantly, flow rates. In the case of refinery and petrochemical plant flare combustion efficiency studies, it was found that flares most at risk for reduced combustion efficiency were those operating at high turndown (low flow) conditions. Low flows also result in reduced exit velocity, where higher exit velocities are more protective against cross-winds. Therefore, it is quite plausible that the majority of the flares encountered in the Plant *et al* study that were operating at reduced combustion efficiencies were flares at low flows. However, the authors applied the destruction efficiencies by *count* of flares to regional flare gas estimates from the Visible Infrared Imaging Radiometer Suite (VIIRS), which inherently incorporates an assumption that flare gas was evenly distributed among the observed flares and that flare turndown was not correlated to combustion efficiency degradation.

Validity of the Plant *et al* Study Data is Questionable

The validity of the Plant *et al* study data as the sole underlying basis for quantifying flare methane destruction efficiency is questionable.

There are several limitations of the Plant *et al* study, most of which are raised by the authors themselves within the study and quoted below. These limitations raise questions about the study validity as a basis for establishing a 3-tier combustion efficiency framework and a presumptive Tier 3 value of 92%. These include:

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[37] https://graham.umich.edu/media/files/F3UEL-Fugitive-Emissions-from-Flaring.pdf.

[38] Ibid.

- The study design did not disclose how the flight-path test method (i.e., 'shifting racetrack' pattern) was validated, for example, using a well-characterized source of CO2 and CH4 or a test flare having known input flow rates, combustion characteristics, and dispersion behavior. Without documentation of method validation using a model source, peer reviewers were, and end-users are, unable to determine how the field sampling techniques were calibrated, and the appropriateness of the error correction / statistical treatment applied to the collected information to address test method-induced artifacts.

- There were no data presented on the vertical or horizontal dispersion effects or on the ability of the sampling technique to discern the presence of imperfect distribution of CH4, CO2 or other components within the sampled plumes. In fact, in the Supplementary Materials[39] the authors noted that (emphasis added), "In real-time, the concentration reading of CO2 was monitored to look for an intercept (i.e., peak) of the ***relatively narrow flare combustion plume as the aircraft transected downwind. If an intercept was not identified on the first downwind pass, the flight team adjusted altitude, using the visual flare as a guide***." This statement confirms that each sample event would likely have employed a unique flight path, introducing an inconsistency across individual runs in the dataset.

- The sampling scenario was challenging. As noted in the Supplementary Materials[40], "In real-time, the concentration reading of CO2 was monitored to look for an intercept (i.e., peak) of the relatively narrow flare combustion plume as the aircraft transected downwind." No information was available to readers to determine the parameters of each flight path. Using publicly available information for the aircraft and assuming a circular flight path, the estimated dwell time of the aircraft in the plume during each pass was likely extremely short. The Scientific Aviation Mooney aircraft have a cruise speed of 170 knots (or higher)[41] with stall speeds of 50-60 knots[42,43] according to various sources. At a speed of 130 knots[44] in a 6500ft diameter circular flight pattern, and assuming a 10^{o} sample window (570ft), the dwell time in the sample window is less than 2.5 seconds. Even with a wide 22.5^{o} sample window (1275 ft), the dwell time in the sample window is just 5.5 seconds. Higher air speeds would shorten the dwell times.

- The study acknowledged that the log-normal curve-fitting technique used likely leads to overweighting the importance of the outlying data, thus magnifying the influence of tails even though the authors noted that the median observed DRE values were close to 98%. Also, the authors could not explain the outlying, tail-defining observations collected (emphasis added), "Investigations into possible drivers of reduced DRE… did not yield compelling explanatory relationships, suggesting that the combination of our airborne sampling and these supplemental datasets ***cannot explain most of the observed flare CH4 DRE variability***." Also, the authors did not solicit input from operators about operating conditions that could explain the observed

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data. Given the influence of the low DRE datapoints, further scrutiny as to their validity and possible exclusion from the dataset should have been made.

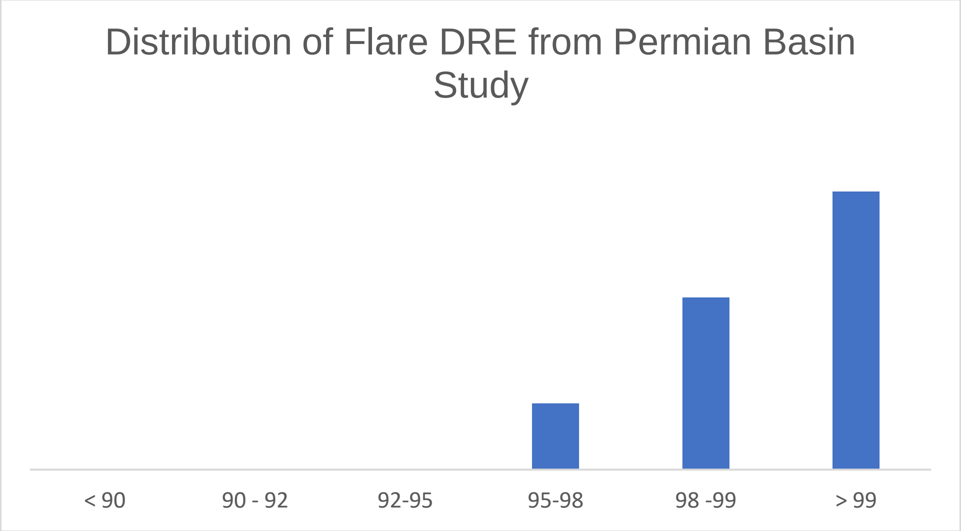
- The Plant *et al* study did not provide information on the rate, duration and variability of the gas being flared at each location, nor what activity precipitated the flaring, such as: flowback from a single well, emergency operations during drilling or a workover, a lightning strike that shut down control systems, a gas compressor failure, malfunction of a tank or separator liquid level or other controller, on a well pad co-located with the flare or at a central gathering and boosting facility, upset at a gas treating unit co-located with the flare, shut-in of a downstream gas plant forcing gas to be flared from multiple upstream sources etc. Absent this information, it is impossible to determine what separated high-performing flares, from those that exhibited low DREs and whether the low-performing flares represent the effect of transient anomalies that cannot be assumed to be present basin-wide for extended periods of time.

- The use of "bootstrapping sampling" to extend to basin-scale the data from the limited sample set collected via aircraft sampling magnifies the weaknesses discussed above and should not be the basis for a regulatory change. The Plant *et al* study authors combined contributions of both observed" inefficient **performance (*i.e., CH4 DRE*) and the prevalence of unlit flares into a total effective DRE."** This was done by randomly resampling (with replacement) the observed DRE distributions and applying those efficiencies to the population of flares seen in VIIRS within each basin. Essentially, this manipulation of the data multiplied the small observed dataset many times over. Then the authors ***inferred the uncertainty*** (emphasis added) of basin-average estimates to derive 95% confidence intervals. This approach does not support the use of the word "found" in the following statement made in the preamble: "Plant *et al*. … ***found*** average combustion efficiencies ranging from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin."

Member-Provided Data Supports a Destruction Efficiency Well Over 95%

Additional flare destruction efficiency data provided by Industry Trade members indicate that all but two flares out of 132 tested achieve a destruction efficiency of over 95%, with the majority (nearly 90%) achieving a destruction efficiency greater than 98%.

In September 2023, API members conducted a flare study on 39 flares throughout the Permian Basin using Providence Photonics Mantis. Due to the limited timeframe in which to prepare comments, this study was limited to 39 flares; however, the study found that 85% of flares achieved a destruction efficiency greater than 98%. All flares achieved a destruction efficiency greater than 95%, as shown in the Figure below.



Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, and one measurement in the Permian, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. All but two flares out of 92 tested had a destruction efficiency above 95% (i.e., 94.85% and 90.52 %, respectively). The table below summarizes the distribution of methane destruction efficiencies calculated from member-provided flare testing in both the Permian and Bakken basins:

Basin	Number of Flares Tested		Mean Flare Destruction Efficiency, %	Median Flare Destruction Efficiency, %
Permian	40		98.82	99.05
Bakken	92		99.27	99.69
Combined	132		99.14	99.50

As shown, the median flare destruction efficiency for the combined dataset of 132 flares tested from the Permian and Bakken was 99.5%. **These studies further reinforce that the Tier 3 destruction efficiency should be a minimum of 95%. Arguably, the Tier 3 destruction efficiency should be considerably higher than 95% based on the test data from members, as the data supports a destruction efficiency closer to 98%.** Please see Annex D for a summary of the test results.

3.8.5 Completion Combustion Devices Should not be Subject to Proposed 98.233(n)

Requirements for completion combustion devices used during completions with hydraulic fracturing should not be required to have the same monitoring provisions as flares under 98.233(n).

For completions with hydraulic fracturing in 98.233(g), EPA has proposed operators to follow the requirements listed in 98.233(n), which include extensive monitoring requirements. Under existing air quality regulations and proposed NSPS OOOOb, combustion of emissions that cannot be routed to sales, such as for wildcat or delineation wells, are combusted using a completion combustion device. This equipment has a separate definition and compliance assurance requirements from typical control devices based under NSPS due to the temporary use of these devices during a completion event. The proposed requirements under 98.233(n) are inappropriate and EPA should, at a minimum, have appropriate provisions that allow engineering estimates for completion combustion events. Completion combustion devices must be equipped with a reliable continuous pilot flame under NSPS.

3.8.6 Disaggregation of Flare Emissions

When data is not available to allow disaggregated reporting by individual sources controlled by a flare, EPA should allow aggregated emissions reporting by flare.

The Industry Trades understand that EPA wishes to allocate all individual sources controlled by a flare back to the contributing source. The Industry Trades support maintaining the ability to report emissions aggregated by flare when more accurate data is not available. As addressed in the "Flares" section of this document, metering individual sources may not result in more accurate data. Allowing the flexibility to continue reporting flare sources aggregated will give companies the ability to report the most accurate data available given a particular facility's operational design. However, it is important to note that EPA has not stated a clear benefit from requiring the disaggregation of sources, and therefore a true cost/benefit analysis cannot be determined.

3.9 Centrifugal and Reciprocating Compressor Venting

3.9.1 Measurements in Not-Operating-Depressurized Mode

The Industry Trades support EPA's efforts to increase the accuracy of reported information for venting from centrifugal and reciprocating compressors by allowing direct measurement, but measurement should not be required in Subpart W if not required in other regulatory programs. Additionally, Subpart W should not force operators to measure emissions in a not-operating depressurized mode.
EPA's proposed expansion from an emission factor to measurement approach for onshore production and gathering and boosting will further improve the quality of reported emissions across the segments. The Industry Trades support the expanded assortment of measurement methodologies and appreciate EPA's use of data from other programs (e.g., proposed NSPS OOOOb and EG OOOOc) for emissions calculations under subpart W, however there are numerous issues with the proposal. Although the compressor measurement provisions have been expanded from the gas processing reporting source category to include onshore production and gathering and boosting, there are unique differences that should be accounted for within the proposed requirements. The Industry Trades have provided suggested edits to account for these differences.

EPA is proposing to require that onshore production and gathering and boosting operators shall measure at least one-third of their reciprocating and centrifugal compressors subject to NSPS OOOOb in not-operating-depressurized mode each year. The Industry Trades do not support this requirement for several technical, safety and practical reasons. The Industry Trades recommend that EPA align with proposed NSPS OOOOb and EG OOOOc and limit the measurements to the rod packing for reciprocating compressors and dry seal vents for centrifugal compressors. Testing the compressors in a not-operating depressurized mode is unnecessary and very difficult to implement for the following reasons:

- Forcing a unit into a not-operating depressurized mode will result in unnecessary venting of methane emissions to the atmosphere and could pose an unnecessary safety risk to the testing personnel or others at the site. Operations in upstream production and gathering and boosting segments are characterized by stable operation with full utilization of installed compression capacity. In order to measure emissions in not-operating depressurized mode, a forced blowdown event leading to significant methane emissions would be required for these compressors.

- As a practical matter, it would be very difficult if not virtually impossible for an operator to know at which point during the year to force units into a not-operating-depressurized mode in order to reach a prescriptive annual target. Additionally, the number of units change on a frequent basis due to acquisitions/divestitures, such that the number that would constitute "one-third" changes from month to month. Compressors are also added and removed throughout the year to address operation needs from the wells and gathering system based on production rates.

- In the dynamic operations of upstream and midstream oil and gas, shutting down a compressor for the sole purpose of measuring the venting could result in shut-in and blowdown of other process equipment resulting in additional methane emissions, as well as costly prolonged downtime of a facility. Taking a compressor off-line in production and gathering and boosting segments would result in shutting in a well(s), which can be problematic to restart and regain stable operation. As anecdotal evidence, our members have noted these tests take upwards of three weeks at their 10 gas plants with 140+ compressors. Extending this requirement to upstream facilities that are geographically spread across hundreds of miles would be extensive due to the thousands of compressors in use. The gas plant measurements are streamlined due to the units being co-located and the designed redundancy in place.

- Additionally, due to the integrated nature of the upstream/midstream environment, shutting down compression would not only have an effect on that company, but would additionally impact other companies that are connected to the system (i.e., shutting a compressor down would cause high pressure issues for the upstream operator and low-pressure issues for the downstream operator potentially resulting in additional flare and/or vented emissions for additional companies.

- Methane emissions from compressors in not-operating depressurized mode represent the emissions across the isolation valve, with potentially high flow rates due to the extreme line pressure on the upstream, pressurized side of the valve. Many operators, especially in production and gathering and boosting segments, do not normally operate compressors in this mode due to the potentially large methane leakage and associated safety risks. Additionally, good operating practice is to leave the blowdown/depressurization valve closed when units are offline.

- Finally, many compressors serve a critical function in the electricity generation supply chain and operate with limited or no excess capacity; forcing operators to shut down units to take measurements in a not-operating depressurized mode could strain the electrical generation supply chain. In 2022, the Texas Railroad Commission (TRRC) adopted weatherization rules for natural gas facilities to protect gas flow to power generators and ensure that residents have electricity during weather emergencies. The new rule requires critical gas facilities to weatherize, to ensure sustained operation during a weather emergency. The testing requirements as described would add an additional layer of complexity with little to no emissions reporting accuracy improvements.

3.9.2 Alignment with NSPS Protocols – Measurement of Compressor Sources

In the proposal for NSPS OOOOb, rod packing, and seal vents are the only compressor sources that require monitoring. All other compressor leaks would be captured during the fugitive emissions inspections. The Industry Trades recommend that EPA align with the monitoring and fugitive emissions requirements of NSPS and consider leaks from other sources (e.g., blowdown valve leakage) fugitive leaks. This modification would eliminate the need for specific compressor mode testing and align with other EPA regulations for other sources.

3.9.3 Emission Factor Methodology- Utilize Measurement Data Reported Under Subpart W for Onshore Production and Gathering and Boosting

EPA should utilize the vast dataset of historically reported compressor measurements in different operating modes to derive population emission factors to ease the burden of compressor measurements and reclassify leakage from isolation and blowdown valves (open-ended lines) as equipment leaks.

While we believe all leaks besides rod packing and seal vents should be captured under the fugitive emissions reporting, EPA could consider an alternative to the measurement protocol. This alternative could utilize the vast dataset of compressor measurements in different operating modes historically reported under Subpart W to derive emission factors to reduce the burden of compressor measurement requirements. Because of the large sample size of actual measurement data, methane emissions can be reasonably estimated using emission factors derived from the data reported Subpart W.

Additionally, EPA should consider the use of the historically reported Subpart W compressor leakage dataset to derive population emission factors rather than rely on the much smaller dataset from the Zimmerle *et al* study.

3.9.4 Alignment with NSPS measurement provisions should extend beyond onshore production and gathering and boosting industry segments.

Industry Trades support referring to the data made available through the provisions located at §60.5380b(a)(5) for centrifugal compressors and §60.5385b(b) and (c) for reciprocating compressors at onshore production and onshore natural gas gathering facilities, but do not support incorporating measurement requirements in Subpart W. The Industry Trades recommend that EPA should also do the same for any compressor subject the NSPS OOOOb or EG OOOOc, including those located at onshore gas processing, natural gas transmission and underground storage. Without this alignment for all compressors subject to the NSPS, many operators will be required to calibrate measurements according to two separate standards, which we do not believe was EPA’s intent.

3.10 Equipment Leaks

3.10.1 Method 2- Site-Specific Leaker Emission Factors

EPA should allow more flexibility in the requirements for developing site-specific emission factors for equipment leaks.

The Industry Trades support EPA’s proposal to allow for directly measured data to develop site-specific emission factors in lieu of the default leaker or population emission factors for equipment leaks. However, the Industry Trades recommend allowing more flexibility in allowing representative direct measurements rather than “site specific.” For upstream operations, there can be many components that are representative even if they are not located at the same facility; and the same can be said for the gathering and boosting reporting segment. The Industry Trades recommend that EPA allow representative leak measurements where "representative" could mean components in gas or oil service, component types, and other considerations – but not otherwise limited to a single well pad or boosting and gathering ID.

The number of leak measurements required to develop site specific emissions factors, proposed as a minimum of 50 per component type, is arbitrary; accumulating 50 leak measurements will be difficult for less frequently used component types or operators with fewer sites. The Industry Trades recommend that EPA allow operators flexibility to determine an appropriate sample size using an appropriate statistical approach based on the complexity of the sites (based on variability of the streams at the sites) and available data and modify as more measurements are obtained. The requirement for a sample of 50 leak measurements per component type will penalize small operators with few sites, as the minimum requirement of 50 may not be possible. Further, as operators convert pneumatic systems to air or electric controllers, fewer sites will have natural gas-operated pneumatics. The Industry Trades also recommend allowing multiple years upon which operators can collect measured leak data and refine those factors as more data is available; this will ultimately be more accurate and representative of site conditions than default emission factors that were derived from larger data sets.

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3.10.2 Method 1- Default Leaker Emission Factors

The derivation of the proposed OGI leaker emission factors is unclear and values appear high relative to the underlying studies and would overstate emissions from the more prevalent non-compressor related components.

The Industry Trades support the use of data from the Pacsi *et al* study to develop the leaker emission factors. However, we are concerned about the significantly higher emission factors that EPA has derived from the Pacsi *et al* and Zimmerle *et al* studies, especially for OGI leak detection, as compared to the existing Subpart W and Pacsi *et al* leaker emission factors. When comparing the published study results from Pacsi and Zimmerle to the EPA proposed emission factors (see comparison table below), it is unclear how the proposed emission factors were derived and while a generalized description is provided in the TSD, the supporting calculations are necessary to fully understand the approach EPA has taken.

Component	**EPA Proposed Emission Factors (scf/hr/component)**			**Pacsi et al (scf/hr/component)**	**Zimmerle et al, (scf/hr/component)**[a]	
	OGI	**Method 21 @ 10,000 ppm**	**Method 21 @ 500 ppm**		Non-compressor components	Compressor components
Leaker EFs, Gas Service – Onshore Production & Gathering and Boosting						
Valves	16	9.6	5.5	6.0	7.1	36.9
Flanges	11	6.9	4.0	13.7	6.2	8.8
Connectors	7.9	4.9	2.8	2.8	4.7	11.9
OELs	10	6.3	3.6	8.5	3.94	
PRVs	13	7.8	4.5	1.1	10.0	18.5
Pump Seals	23	14	8.3	-	29.9	
Other	15	9.1	5.3	4.2	21.7	
Leaker EFs, Oil Service – Onshore Production & Gathering and Boosting						
Valves	9.2	5.6	3.3	4.9	7.1	36.9
Flanges	4.4	2.7	1.6	-	6.2	8.8
Connectors	9.1	5.6	3.2	1.1	4.7	11.9
OELs	2.6	1.6	0.93	-	3.94	
Pump Seals	6.0	3.7	2.2	0.23	29.9	
Other	2.9	2.2	1.0	12.7	21.7	

[a] Zimmerle *et al* study published results did not distinguish between gas and oil service.

As shown in the table above, the Zimmerle *et al* study data show and the study report indicates that emissions from compressor-related components have higher leak rates due to vibration. Since EPA did not distinguish between components associated with or not associated with compressors, the average emission factors proposed that appear to include compressor-related components would overstate emissions from the more prevalent non-compressor related components. The Industry Trades request that EPA critically review the derived emission factors and include compressor-related components in the breakdown of leaker emission factors, with commensurately lower emission factors for non-compressor-related components, to avoid significant overstatement of methane emissions from the higher population of non-compressor related components.

Applying gathering and boosting derived emission factors to onshore production with compressor-related component emissions included in the Subpart W emission factors would significantly overstate methane emission because far fewer compressors are operational in production compared to gathering and boosting operations.

The Industry Trades support efforts to properly characterize a leak by the period in which that leak is detected. This will further align subpart W with the proposed methane rule, which mandates that any leaks must be repaired as soon as practicable. To that extent, we recommend EPA amend the definition of $T_{p,z}$ in Equation W-30 to better reflect the implementation of monitoring and repair programs by acknowledging that the duration of the leak may be subject to the action of repair and verification, and not solely by a traditional survey and/or the start or end of the reporting year, similar to what the Industry Trades propose for other leak durations, thief hatch openings, etc.

We also recommend that EPA revise the approach to include other activities in addition to leak detection surveys that may offer an indication of a repaired leak. While the current proposed language refers only to a “survey”, an operator will have other clear indicators that a leak has been addressed including the repair date or other detection approach. EPA should include any other such activity on which an operator seeks to assign a repair date other than a survey as a reporting element.

3.10.3 Enhancement Factor

EPA’s ‘Enhancement Factor” or “k factor” derivation and rationale are unclear; testing of the proposed approach using the underlying study data to corroborate results should be confirmed.

EPA states in the TSD that the Pacsi *et al* study OGI captured approximately 80% of overall emissions, Method 21 (500 ppm leak detection threshold) captured 79% of emissions, and Method 21 (10,000 ppm limit) captured 65% of emissions, respectively. However, the Pacsi *et al* study is clear that even though using Method 21 identified more leaks (293 vs. 113 with OGI), the majority (67%) of additional leaks found were very small (1 scf/hr. or less). Further, both FID and OGI methods, while finding different leaking components, found a very similar total volume of emissions from leaking components at the site.

The Industry Trades disagree with EPA’s proposed “Enhancement Factor” or “k” factor. It seems that EPA has proposed the ”k” factor to account for both method’s quantification differences as well as other variables, such as the percentage of emissions found by survey methods (e.g., due to accessibility of components, etc.). Applying such logic to specific emission factors for specific equipment is not appropriate as the intent seems to include both updates for a specific leak factor for an individual component as well as capturing emissions from other components that may not be otherwise detected (i.e., the remaining 20% or 21% of emissions not directly identified by OGI or M21 respectively in the Pacsi *et al* study). Grossing up individual component emission factors is not a logical approach to account for leaks not directly identified. While the Industry Trades disagree in principle with EPA’s approach, if such an approach were to be applied, it would only be appropriate on an aggregate basis. That is, if EPA were to apply such logic, doing so as part of the National Inventory process would be more appropriate than grossing up emissions from induvial components or individual operators.

Additionally, and importantly, the Industry Trades have been unable to replicate the calculations EPA used to derive the “k” factors and request transparency regarding the approach and use of data relied upon by EPA prior to finalizing any rulemaking. The Industry Trades also request confirmation if EPA tested their “k” factors by applying to the M21 data in order to recalculate the emissions at site level using study data and confirm if it matches with the measured emissions.

3.10.4 Leak Duration

The leak duration should be revised to reflect a more reasonable and representative assumption that the leak duration is half the time since the last survey.

The leak duration associated with the Method 1 leaker emission factor approach should be half the time since the last survey. Assuming that the leak duration was the entire period since the last survey is an overstatement of the leak duration, as it implies the leak occurred on the date of the last survey which is unreasonable. Since the actual time the leak started is unknown, it is more reasonably accurate to assume that, on average, that the leak would have started in the mid-point of the survey cycle. This assumption accounts for that some leaks will occur before the mid-point and some will occur after the mid-point, but that on average, it is a reasonable assumption and much more representative than the conservative assumption that the leak started at the time of the last survey.

3.10.5 Method 3 – Default Population Emission Factors

The proposed population emission factor approach should be revised to improve accuracy of emission factors and component counts, while allowing more flexibility for reporters.

The Industry Trades are concerned that the Rutherford *et al* study (2021) used for the production and Gathering and Boosting emission factor development included infrequent large emitters in the derivation of the emission factors, including emissions from sources covered elsewhere and not considered fugitive components. Additionally, Rutherford *et al* didn't conduct any actual measurements of equipment leaks. The study results are a synthesis of past studies and includes storage tank emissions as fugitives. Given that EPA is now proposing to report large events as “other large releases,” the Industry Trades believe using this study will result in double-counting. The Industry Trades support the use of the Pacsi *et al* and Zimmerle *et al* studies, despite EPA’s concerns noted in the preamble regarding the smaller sample size. The Industry Trades believe the Pacsi and Zimmerle studies to be more appropriate for upstream and midstream operations.

The Industry Trades do not support the elimination of component count method 2 and request that EPA allow the use of actual component counts if it is subject to a state regulatory program that requires component counts.

3.10.6 Leak Detection at Onshore Gas Processing

Industry Trades generally support the updated definition of onshore natural gas processing that align with New Source Performance Standards as proposed in 98.230(a)(3). This update provides the regulated community with much needed alignment between regulatory programs and removed the confusion for reporting emissions under subpart W based on the previous definition included in the GHGRP.

However, the Industry Trades request that **CO_2 plants be included within the Onshore Gas Processing segment definition**, and not under the Gathering and Boosting definition.

Additionally, there are additional clarifications that are needed from EPA to the proposed equipment leak provisions as it pertains to onshore gas processing to better align with existing and proposed NSPS provisions.

The proposed use of NSPS OOOOb and EG OOOOc surveys for calculating emissions should be clarified and expanded.

EPA has proposed the following text at 98.233(q)(1)(vi)(F) to require the use of NSPS OOOOb and OOOOc survey data in calculating emissions from equipment leaks at onshore natural gas processing plants:

> *For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), including components which are considered inaccessible emission sources as defined in part 60 of this chapter.*

Industry Trades recommend the following updates to this requirement:

- **Inclusion of alternate leak standards**: References to § 60.5400b should also include a reference to the alternate equipment leak standards in § 60.5401b to clarify that both OGI surveys conducted according to Annex K and Method 21 surveys with a 500 ppmv leak definition should be used in emission calculations.
- **References to the equipment leak standards under the earlier NSPS KKK, OOOO, and OOOOa** should be included so that survey data can also be used in emission calculations. While the earlier equipment leaks standards were for VOC only as opposed to the VOC and methane under NSPS OOOOb and EG OOOOc, some components in VOC service (>= 10 wt% VOC) may also be required to be surveyed under Subpart W (>=10wt% CH4 + CO2), and the monitoring technique in the earlier NSPS are already included in the approved list in 98.234(a). This update would allow operators to avoid potentially duplicative surveys.
- **The inaccessible component exemption should be retained under Subpart W.**[45] For onshore gas processing, the term "Inaccessible" has a long-standing meaning under NSPS, which historically is limited to connectors that are monitored using Method 21 with specific criteria that extends well beyond the 2-meter clause noted in 98.234(a). This exemption is directly linked to the safety of our personnel or the technical use of monitoring equipment. Specifically, connectors that are *"buried"* or that are "*not able to be accessed at any time in a safe manner to perform monitoring (Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or*

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[45] EPA has proposed the following language per 98.234(a): Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year. For components located in the onshore production, natural gas gathering and boosting, transmission compression and underground storage (i.e. well sites, central production facilities, or compressor stations), the language proposed aligns with those that are identified at difficult-to-monitor when using M21 per the provisions in NSPS OOOOa and proposed NSPS OOOOb/c. The difficult-to-monitor components require annual monitoring under NSPS, which are consistent with the proposed language in 98.234(a). EPA could be consistent and use the term difficult-to-monitor if that was EPA's intent.

> *uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment)"* should not require additional leak detection provisions under subpart W.

3.10.7 Expand List of Approved Monitoring Technologies

The list of approved monitoring technologies should be expanded to include alternative periodic screening and continuous monitoring technologies.

Under proposed NSPS OOOOb and EG OOOOc[46], operators have the ability to use EPA approved alternative periodic screening or continuous monitoring technologies to satisfy the equipment leaks for well sites, centralized production facilities, and compressor stations. The Industry Trades have provided previous comments[47] on how to improve these proposed alternative technology provisions. Furthermore, results from alternative technology surveys could not be used for Subpart W emission calculations as proposed. Therefore:

- Operators would need to conduct an annual OGI or M21 survey for Subpart W for components subject to NSPS OOOOa/b/c or for other components if they elected to not use the population emission factors. This annual survey could be beyond what is required under NSPS.
- Results from use of alternate technology under NSPS OOOOb or EG OOOOc would be reported under large emissions release if thresholds were exceeded under Subpart W.

These two consequences would disincentive the use and development of alternate leak detection technologies. Therefore, 98.234(a) should be updated to include: “Periodic screening or continuous monitoring as specified in § 60.5398b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter…”

3.10.8 Component Applicability

The Industry Trades support EPA’s proposal to exempt “components in vacuum service” from the equipment leak provisions in 98.233(q) and (r). These components have been historically exempt from the NSPS leak detection standard since no fugitive leaks are expected. However, we do not support inclusion of reporting requirements that include reporting of component counts for components in vacuum service.

3.11 Other Large Release Events

The Industry Trades support inclusion of a category of other large release events in Subpart W reporting requirements because these sources have been observed across many basins, and literature has demonstrated that they can have an outsized impact on total emissions. However, both the threshold and triggers for inclusion of an event based on credible information are problematic. Furthermore, in many cases it will double count emissions reported elsewhere in the regulation.

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[46] Proposed § 60.5398b and § 60.5398c.

[47] The Industry Trades have provided previous comments on how to improve these proposed alternative technology provisions. See Comment 3.0. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428 https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-3819

3.11.1 Other Large Release Events Threshold

3.11.1.1 Instantaneous Rate of 100 kg/hr is Not a Meaningful Threshold

A threshold of an instantaneous rate of 100 kg/hr should be paired with a duration in order to ensure that the observation is, indeed, associated with a large release event. A measurement report of an instantaneous rate of 100 kg/hr should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event.

EPA explains that it "is proposing revisions to include reporting of additional emissions or emissions sources to address potential gaps in the total CH_4 emissions reported by facilities to subpart W."[48] "These revisions include proposing to add a new emissions source, referred to as ''other large release events,'' to capture large emission events that are not accurately accounted for using existing methods in subpart W."[49] An "other large release event" would be defined to include any event that exceeds an instantaneous methane emissions rate of 100 kg/hr or exceeds 250 mt CO_2e for the entire event.[50]

EPA further explains that the 250 mt CO_2e event-based threshold is based on a comparison to the Aliso Canyon event and other release scenarios that EPA considers to be objectively large. EPA asserts that the 100 kg/hr instantaneous emissions rate threshold is appropriate because it would "align with the super-emitter response program proposed in the NSPS OOOOb" and would "provide a means to get information for these large, shorter duration releases."[51]

The proposed reporting thresholds for "other large release events" are flawed for two reasons. First, EPA fails to provide any explanation of whether the reporting thresholds are appropriate or necessary for purposes of implementing the WEC. As explained above, the key purpose of the Proposed Rule is to provide information necessary for implementing the WEC. There are obvious questions that should be asked and answered by EPA as to how the type and scope of "other large release events" that would be required to be reported under the Proposed Rule squares with implementation of the WEC. EPA's views on the relationship between the proposed reporting thresholds and implementation of the WEC are necessary for EPA to fully assess the impact of the Proposed Rule and to allow for commenters to assess EPA's reasoning and provide informed input.

Since oil and gas emissions are highly variable in rate and duration, an instantaneous observation, even if extrapolated to provide results in units of an hourly emission rate as is typical, merely provides information regarding potential observations of far less than the represented hour in most cases. This is because an emission source with duration greater than 1 hour may have a variable rate over that hour or an emission source may resolve in far less than the hour. An instantaneous threshold of 100 kg/hr methane could result in numerous objectively small emission events (especially compared to an objectively large event release of at least 250 mtCO2e). An emission duration, assuming perfect observation and consistent emission rate of 1, 100, or even 1,000 times the <1 minute observation period for many technologies (assume 1

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[48] 88 Fed. Reg. at 50284.

[49] Id.

[50] Id. at 50296.

[51] Id. at 50296-7.

minute here), would result in emission event quantities of 0.05, 4, or 42 mtCO2e or 0.02%, 2%, or 17% of the corresponding 250 mtCO2e threshold. In fact, it would take nearly 5 days of a constant emission rate of 100 kg/hr to accumulate emissions of 250 mtCO2e, of which there is no reasonable extrapolation of an instantaneous remote sensing emissions event.

Therefore, an instantaneous rate of 100 kg/hr is not a meaningful threshold to indicate that an emission source is large or even otherwise unaccounted, since multiple intended and accounted for emissions have transient large emission rates (blow downs, drilling completions, liquid unloadings, etc.). Such data should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event. emissions.

3.11.1.2 Other Large Release Threshold Needs to be Modified

If Other Large Releases Remain in the Rule, Modify the Threshold

At a minimum, the Industry Trades recommend that EPA modify the threshold for this category in 98.233(y)(1)(i) as follows (and modifying 98.233(y)(1)(ii) as applicable):

(i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that~~either~~:

(A) Emits methane at any point in time at a rate of 100 kg/hr or greater; ~~or~~ **and**

(B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more.

Requiring both thresholds be met would catch large releases discussed in the proposed rule's TSD, such as well blowouts, while also easing the burden on reporters to assess relatively smaller emission events, such as PSV releases that occur over a few seconds to minutes.

If EPA does not change the threshold as recommended below, the Industry Trades recommend that a duration of 100 hours be paired with the instantaneous rate of 100 kg/hr, which is commensurate with a duration at that emission rate that would result in 250 mtCO2e of

3.11.2 Detection Technology Must be Approved by the Super-Emitter Response Program

Furthermore, the Industry Trades are requesting that EPA clarify that the rate of 100 kg/hr is determined with only advanced detection technology and third parties approved by EPA through the SERP in NSPS OOOOb and not based on presumptive calculations, models, or ground sensors which have varying levels of uncertainty. Furthermore, if industry is not approved to use the technology for compliance with OOOOa, OOOOb, or OOOOc, the technology should not be required to be used for reporting purposes under Subpart W and used to determine fees under the WEC. Requiring this will discourage voluntary monitoring by companies, discourage new technology development, and include potentially highly inaccurate data to be the basis of the WEC.

3.11.3 Other Large Release Events Duration

EPA is proposing that reporters must assume a leak duration of 182 days if the start time of an event cannot be determined based on "monitored process parameters." EPA has no basis for using 182 days.

As noted in the proposed rule's TSD, typical durations for large releases are several hours to several days. The Industry Trades believe this 182-day assumption is derived using average leak duration data including a significant statistical outlier event[52] that should be excluded from calculated averages, most notably because the time it took to resolve the leak was not due to lack of awareness of the leak, but rather the complexity of resolving the leak. Accordingly, the Industry Trades disagree with EPA's statement in the TSD that the duration should not be shorter than the Aliso Canyon event. Besides it being a known event, EPA is proposing a default leak duration even longer than that statistical outlier event (111 days vs. 180 days).

The Industry Trades recommend a duration of half the time since the last optical gas imaging inspection, or the time since operator inspection of the source in question (e.g., operator rounds that proactively include flare, thief hatch or other inspections), site level measurement campaign, continuous monitoring system, or other monitoring data, or a maximum of 30 days if no other data is available. The maximum duration of 30 days is a conservative estimate consistent with (a) EPA's acknowledgement in the TSD that "Studies on large releases from oil and gas facilities commonly report that these emissions are intermittent, with typical durations of several hours to several days (Chen *et al*., 2022; Wang *et al*., 2022)", and (b) that most well sites are expected to have operator rounds occurring more frequently than every 30 days and, further, the odds of a significant event going unnoticed by both and operator and 3rd parties (satellite, etc.) are unlikely.

Furthermore, the Industry Trades believe that additional clarification and flexibility needs to be provided for "monitored process parameters." This is particularly critical for very short emission events for which telemetry may not be available or reliable. The Industry Trades are concerned that any ambiguity around this requirement could result in vast over-reporting of emissions by assuming a duration of 182 days. Monitored process parameters are not defined in the rule, but in 98.236(y)(4) EPA says that this includes "pressure monitor, temperature monitor, other monitored process parameter (specify)." The Industry Trades recommend clarifying this by allowing reporters to use additional process parameters, such as site inspections, cameras on location, etc. that confirm the event duration.

3.11.4 Credible Information

EPA is proposing that operators must report emissions from other large release events if they have "credible information" that a large release event has occurred. The Industry Trades are concerned that requiring reporters to use all credible information, especially where credible information in this context is ill defined, may disincentivize voluntary monitoring with emergent technologies where leaks could be discovered, but may have a large range of uncertainty (generally associated quantitative emissions estimates and short observational periods of less than 1 minute). Paradoxically, the shorter duration measurements tend to have higher accuracy in quantification for the short duration and the longer duration measurements tend to have emission estimating uncertainties that can span orders of magnitude. The Industry Trades recommend that EPA define "credible information" in a way to allows operators to use regulatory-driven inspections, allow for additional parameter monitoring while accounting for telemetry malfunctions, site inspections or camera monitoring, and engineering estimates to determine if a release has occurred and is subject to reporting.

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[52] Underground storage station well blowout near Los Angeles, CA (i.e., Aliso Canyon) in 2015, event duration was 112 days as opposed to other events which were significantly shorter.

3.11.5 3rd Party Event Reporting

In 98.236(y), EPA is proposing that reporters must report any events identified through a potential super-emitter release. The Industry Trades urge EPA to implement guardrails around what and how a third-party could report, which is particularly impactful for those subject to SERP. Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality and accuracy of those reports (including, but not limited to, data integrity, completeness, free from atmospheric interference, timing or greatly delayed notification, etc.). While the industry strives for excellence in reducing large release events, resources which would otherwise be utilized to minimize emissions could be diverted to respond to large volumes of unfounded third-party notifications which may have no basis in reality.

The proposed requirement to consider third-party release reports is beyond EPA's authority.

Additionally, the **Industry Trades request EPA to clearly define the scope of credible information that would trigger additional investigative and reporting burdens**. The Industry Trades are concerned that unqualified third-party reports developed by unqualified operators could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear guidelines on who would be qualified to provide third-party reports and the associated duration of an observation necessary to trigger investigation and reporting obligations under Subpart W.

EPA proposes that third-party reports of "other large release events" submitted under NSPSSubparts OOOOb or OOOOc must be documented and addressed under Subpart W.[53] **API explained in its comments on the Subpart OOOOb and OOOOc proposed rules that EPA does not have authority to allow third parties to generate information that triggers regulatory requirements for affected/designated facilities.**[54] We incorporate by reference those comments here. Because the proposed third-party reporting requirements under Subparts OOOOb and OOOOc are beyond EPA's authority, those requirements should not be finalized and, by extension, should not be referenced or incorporated into the Subpart W provisions addressing "other large release events."

To begin, it is not possible to discern without further explanation from EPA who might constitute "another third party." That ambiguity makes it impossible to devise and submit informed comments on this aspect of the proposed reporting requirement.

Having said that, it is possible that EPA intends "another third party" to mean an entity submitting information to an affected facility outside of the third-party reporting provisions established under NSPS Subparts OOOOb or OOOOc. If that is the case, this aspect of the Proposed Rule is inadequate because EPA fails to explain the legal basis for imposing such requirements, including why such a requirement might be a reasonable under CAA § 114. Such a requirement would, in any event, be outside of EPA's CAA § 114 authority because CAA § 114 authorizes only EPA to collect information. It does not authorize EPA to impose a mandatory reporting obligation that would be triggered by third-party observations or

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[53] 88 Fed. Reg. at 50433.

[54] API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," EPA-HQ-OAR-2021-0317-2428 at 97-99.

assertions. If EPA believes that information about "other large release events" not reported pursuant to NSPS Subparts OOOOb or OOOOc should be reported by affected facilities, EPA must initiate the information request and may not rely on reports submitted by third parties.

Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality (including data integrity, completeness, free from atmospheric interference, timing of or significant delay in notification, etc.) and accuracy of third-party reports. The Industry Trades may submit supplemental comments after the Oct. 2 deadline.

At this time, the term "credible" is not defined in this rule. The Industry Trades recommend that EPA adopt the Industry Trades recommendations for SERP, and 98.236(y) is modified to only include events which EPA deemed credible under the SERP, and modify the citation below as follows:

> *(y) Other large release events. You must indicate whether there were any ~~other~~ credible large release events from your facility during the reporting year and indicate whether your facility was notified of a ~~potential~~ credible super-emitter release under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If there were any ~~other~~ credible large release events, you must report the total number of ~~other~~ large release events from your facility that occurred during the reporting year and, for each ~~other~~ credible large release event, report the information specified in paragraphs (y)(1) through (10) of this section. If you received a notification of a potential super-emitter release from a third-party for this facility or a super-emitter release notification under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.*

The Industry Trades are re-iterating our previously submitted comments regarding the credibility of those 3rd-parties reporting[55] as proposed in NSPS OOOOb. In short, the Industry Trades reiterate the importance that any third-party conducting these monitoring events should be certified by EPA to be included in the SERP.

In general, the Industry Trades are concerned that events reported under other source categories, such as "blowdowns," thief hatches or equipment leaks could inadvertently be double counted under other large release events. The Industry Trades requests that EPA codify clear guidance on how to ensure that information reported by a 3rd party can be appropriately subtracted from events that could reasonably be reported under another category.

3.11.6 Other Concerns Regarding Other Large Release Events

The Industry Trades request that EPA remove the latitude/longitude reporting requirement proposed in 98.236(y)(11)(iii), and instead allow county-level reporting for pipeline release events (consistent with PHMSA requirements). If EPA maintains the requirement to report latitude and longitude of the release event, the Industry Trades request that EPA clarify that these events at sites other than pipeline locations may consist of a single latitude/longitude for a site (and should not include the granular latitude and longitude of the individual component).

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[55] API Comments on NSPS OOOOb and EG OOOOc Supplemental Proposal letter, dated February 13, 2023. Section 1.1.

Furthermore, remote sensing technologies generally do not distinguish between emissions sources that are transient, included sources (blow downs, liquid unloadings, crankcase venting, etc.), or unintended sources that may or may not already be identified (unlit flares, over pressurized tanks, etc.) and thus there is a risk for double counting of certain emissions. Owner/operators should exclude sources that are already otherwise accounted for under another category, and EPA should explicitly allow exclusion of observations that could be classified as large emissions events but are otherwise already accounted for in another category.

To address one of EPA's requests for comments in the preamble, the Industry Trades believe that reconciling top-down data with bottom-up data should not force reporters to revise bottom-up estimates. The values recorded by these top-down sensors require significant data processing and analytics to provide the required measurement values, including concentration or flux. Moreover, even if the concentration (or concentration-pathlength) were perfectly accurate, error is introduced in post processing to produce estimates of emission rates, and these errors vary greatly depending on both the technology deployed, but even proprietary data treatment techniques between vendors of similar technologies. Beyond these uncertainties, however, is an inherent uncertainty introduced due to the temporal misalignment between the observational data and the bottom-up reporting methods. Not only do "matching" style reconciliation exercises require high spatial resolution of bottom-up emissions estimates (disaggregation to sites or even to the equipment level), but such exercises demand high temporal resolution. Otherwise, reliable extrapolation techniques must be applied to the often short duration observations to produce longer term emissions estimates. The aggregation of these uncertainties implies that the "top-down" measurements cannot be deemed more accurate, but simply useful in that they provide a different view of emissions.

3.12 Reporting Combustion Sources in Subpart C versus Subpart W

Emissions from natural gas combustion are *not* waste emissions that should be subject to the methane fee but are a result of the end use of natural gas within the value chain; emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations.

The Industry Trades appreciate that EPA intends to provide clarity on when reporters can use subpart C calculation methodologies instead of Subpart W, including defining the applicable gas quality. However, EPA has not provided sufficient information to justify the composition threshold of natural gas in determining between use of Subpart C or Subpart W calculation methodologies. EPA, in the TSD-W, concluded that the appropriate threshold criteria for use of subpart C includes a natural gas composition of 85% CH_4, but this threshold does not appear to represent any national or basin-wide average of the composition of fuel gas. EPA must provide additional information regarding the election of the 85% CH_4 composition threshold as a criteria for use of Subpart C methodologies.

As the Industry Trades previously commented during the June 2022 proposal, EPA should move all combustion calculations and reporting requirements from Subpart W to Subpart C to conform with the structure of the rule for other industries reported under the GHGRP. This would eliminate the current and proposed confusing structure that splits oil and gas combustion emissions across multiple subparts and references back and forth between the two subparts.

EPA seeks comment on "amending Subpart W to specify that all industry segments would be required to report their combustion emissions, including CH_4, under Subpart W to more accurately reflect the total

CH4 emissions from such facilities within the emissions reported under Subpart W." EPA asserts that Section 136(h) of the CAA specifies that EPA must "revise the requirements of subpart W…. [to] accurately reflect **the total CH_4 emissions and waste emissions** from the applicable facilities and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, **to demonstrate the extent to which a charge under subsection (c) is owed**" (emphasis added). Methane slip emissions from combustion are *not* waste emissions that are subject to the methane fee but are a result of the end use of natural gas within the value chain. Therefore, such emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations, when they are defined under future EPA rulemaking.

The IRA includes several statements that clarify the definitions of waste with regards to methane emissions within the rule. The IRA includes provisions for exemptions based on regulatory compliance with new source performance standards and state-level implementation of existing source rules that are equivalent or greater in emissions reductions to EPA's November 2021 Methane Rule framework. Neither the 2021 Methane Rule Framework nor the subsequent December 2022 proposal for NSPS OOOOb and EG OOOOc include source performance standards for methane slip from compressor engines. While not directly applicable to the methane fee, Section 50263 of the IRA clarifies that royalties on all extracted methane emissions on Federal lands and the Outer Continental Shelf have a stated exception for "gas used or consumed within the area of the lease, unit, or communitized area", which clearly would exempt the routine use of fuel gas, and associated methane slip emissions, from such royalty calculations. Considering these statutory provisions of the IRA, methane slip from compressor engines should not be included within the emission calculation framework for Subpart W and the eventual methane fee calculations that EPA will define at a later date.

3.13 Methane Slip from Incomplete Natural Gas Combustion

Direct measurement and the use of default equipment-specific destruction efficiencies should be allowed regardless of fuel type, and EPA should allow for control efficiencies from emerging technologies.

The Industry Trades agree with the agency that the default combustion efficiency for incomplete combustion or "methane slip" should be updated. However, it is important to note that the changes to methane combustion slip emission factors are expected to result in one of the largest changes to reported methane emissions, and EPA should allow the use of performance tests to determine methane slip factors regardless of fuel type. This would critically incentivize investments in technologies to reduce methane slip and would meet the objective of using empirical data. However, EPA should include these revisions under Subpart C instead of under Subpart W.

EPA's basis for exclusively using default equipment-specific destruction efficiencies, when the fuel does not meet at least 950 btu/scf, and contains less than 1% CO2 and at least 85% methane by volume is flawed. We recognize that EPA tried to simplify the performance test requirement to a one-time performance test, and as such did not propose to allow performance testing because fuel types "are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions." The Industry Trades make two comments on this assertion. First, operator experience indicates that field gas is not significantly variable year over year and EPA does not provide data to support its assertion. Second, EPA does not explain why the range of any expected variability would result in a change in combustion slip. Third, and most importantly, reporters commonly conduct performance testing on engines to meet NSPS JJJJ/NESHAP ZZZZ or state regulatory requirements. As such, EPA should allow reporters to use those results regardless of the fuel gas type, as well as the default equipment-specific combustion efficiency for reciprocating internal combustion engines (RICE) and gas turbines (GT), as long as the performance test results are only applied to sites with similar fuel gas quality.

To further emphasize the importance of allowing performance test data from any RICE or GT, the Zimmerle study cited by EPA is representative for natural gas compressor stations, but it does not include any smaller engines likely to be found in an upstream environment. Allowing directly measured data will both provide EPA with additional details regarding methane slip related to the smaller engines, and it will allow operators to use empirical data as aligned with EPA's intent. Critically, this will also incentivize operational improvements to reduce methane slip from natural gas combustion. This also clears up the proposed discrepancy where EPA proposes to mandate incorporation of performance test results for some RICE and GTs, but prohibits the use of performance test results for others. Ultimately, there is no reason EPA should not allow operators to use results from periodic performance tests conducted per EPA reference methods regardless of fuel quality.

The table below summarizes the distribution of combustion efficiencies calculated from member-provided performance tests:

Horsepower	Count	Minimum Combustion Efficiency	Mean Combustion Efficiency	Median Combustion Efficiency	Maximum Combustion Efficiency
> 500 hp	76	96.16%	98.29%	99.46%	99.46%
< 500 hp	57	98.29%	99.58%	99.99%	99.99%

The above data is based on performance tests using engine horsepower, load, break-specific fuel consumption, the average grams of methane per horsepower-hour over three test runs, and the methane concentration of fuel gas. The combustion efficiencies were derived by dividing the stack test mass of methane by the mass of methane consumed in the fuel gas. The results show that minimum stack test combustion efficiency for engines greater than 500 horsepower is on par with EPA's equipment-specific default combustion efficiency for 4 stroke lean burn engines; while the combustion efficiency for engines less than 500 horsepower is greater than EPA's equipment-specific combustion efficiency for the same engine type. The data illustrates how smaller engines typically have favorable combustion efficiencies given they have smaller cylinder bores. The Industry Trades believe that allowing operators to develop horsepower-specific destruction efficiencies based on performance tests would lead to more accuracy while meeting EPA's intent to measure combustion slip from internal combustion units.

EPA should also allow for flexibility to incorporate methane controls as new technologies are being developed to control methane emissions from RICE. The Industry Trades recommend that EPA add a methane control efficiency parameter to Equation W-39B to allow for flexibility of incorporating a control efficiency to enable reporters to report methane slip more accurately when methane control technologies emerge and are demonstrated to be effective.

Allowing for the use of additional approaches to calculate methane slip from compressor engines would further support technology development. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program (REMEDY | arpa-e.energy.gov) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in natural gas fired lean burn engines. If technology development from this 3-year, $35 million research program is successful, the ability to use updated values in methane emissions reporting could help to drive greater adoption of new technologies in operations.

3.14 Drilling Mud Degassing

In proposed Calculation Method 1, EPA is proposing to quantify drilling mud degassing by applying an emission rate derived from a representative well in the same sub-basin and at the "same approximate total depth." The Industry Trades request clarification on how to determine the "same approximate total depth."

EPA has proposed that operators must use mudlogging measurements taken during the reporting year, and therefore calculate emissions using Methodology 1. The Industry Trades disagree with this requirement, as it is possible a mudlogging measure is taken at the very early stages of a drilling operation, and that measurement may not ultimately be reflective of the entire duration of the drilling operation. The Industry Trades recommend allowing reporters to use Methodology 2 for all active drilling. The Industry Trades also propose a third option (see next comment), in the event that some mudlogging data is available.

The proposed third option would serve as a combination of the currently proposed Method 1 and 2. As stated above, this would allow operators to use a combination of the two methodologies when a varying level of directly measured data is available. In this third option, mudlogging measurements would be used based on Method 1 for the period in which the data is available, and Method 2 would be used for the remaining period of drilling activity where mudlogging data is not available. This method should also allow operators to account for drilling mud degassing vapors sent to a control device.

EPA is proposing to calculate emissions from drilling mud degassing based on the total time that drilling mud is circulated in the representative well. The Industry Trades request that EPA clarify that this should be calculated based on circulating time in the hydrocarbon bearing zones only (i.e., excluding surface holes drilled by a spudder rig when no hydrocarbons are present).

One further complication of the proposed method for quantifying methane emissions from drilling mud degassing is that the concentration of natural gas (or methane) in drilling mud is not currently specifically measured and is difficult to obtain. Further, it is not measured by mud loggers in units of ppm, as the measurement instrument used is in units that are not representative of methane concentration.

3.14.1 Proposed Calculation Method 2

EPA is proposing the following emission factors in MT CH4 per drilling day for drilling mud degassing: 0.2605 for water-based drilling muds, 0.0586 for oil-based drilling muds, and 0.0586 for synthetic drilling muds. The EPA based these factors on a study evaluating emissions from offshore drilling from 1977, which is both outdated, and not representative of most onshore drilling operations in the United States. Furthermore, these outdated factors are based on mud throughput, but the basis remains unclear. The Industry Trades reiterate that the emission factors compiled in the 2021 API Compendium for Well Drilling and mud degassing (Section 6.2) is appropriate for the well bore and porosity conditions for onshore drilling operations as it was developed specifically for onshore operations. Use of the proposed offshore emission factors for onshore drilling operations will significantly overstate methane emissions from onshore production mud degassing. The Industry Trades suggest that the emission factor should be derived as a function of well dimensions to better represent mud degassing emissions. Otherwise, the Industry Trades recommends that proposed methodology 2 be revised based on drilling time in hydrocarbon hole section, and not overall event days. There can be multiple days in a hydrocarbon hole section where the pumps are not circulating.

3.14.2 Reporting Requirements

Reporting requirements proposed in 98.236(dd) require reporting total vertical depth of the well, and the circulation time of the drilling mud within the wellbore. The Industry Trades do not support reporting this information, as EPA did not address why the information would be requested. Furthermore, total vertical depth would not provide representative information for horizontal wells and would not improve the reported data quality.

3.15 Crankcase Venting

In general, the Industry Trades support the use of actual test data for crankcase venting when available, while still allowing the use of a provided emission factor. However, the Industry Trades believe the emission factor for this activity should be derived based on horsepower in order to be more reflective of operations in the onshore production or gathering and boosting segments, should include the ability to take credit for routing the emissions to a control device, and do not believe this emission source category should include gas turbines. The study cited in the TSD included an audit of three gas compressor stations and two natural gas storage sites[56]. These facilities are expected to have a much higher vent rate than in production operations due to the larger engine size required in gas compressor stations and gas storage. Therefore, the proposed average emission factor may reflect an overestimation of this source for upstream production and many smaller gathering and boosting facilities. The Industry Trades suggest that EPA considers deriving an emission factor based on engine horsepower instead of vent count, as the vent rate is correlated with engine size rather than number of vents.

As proposed, there is no method to reflect reductions if emission controls are developed and implemented or crankcase venting is routed to a control or combustion device. The Industry Trades recommend adding this flexibility by including a control efficiency parameter in Equation W-45, which also has the added impact of incentivizing controls where feasible.

The Industry Trades also recommend that EPA provide clarification around how to account for crankcase vents which are manifolded together, as the reporting requirements are on a per-vent basis.

EPA is proposing a reporting requirement for the average operating hours for each reciprocating internal combustion engine or gas turbine. The Industry Trades recommend the removal of this “average” data; it is duplicative and requires operators to average numbers used in calculations for the sole purpose of reporting this element. The Industry Trades recommend removing this data reporting requirement or leaving the reporting requirement on a per-site basis of total operating hours.

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[56] Johnson *et al.*, 2015

Additionally, the factor prescribed by EPA is based on an API study,[57] which only represents reciprocating engines, and not natural gas turbines. The study's definition of crank case is, "The crank case on *reciprocating engines* and compressors houses the crank shaft and associated parts, and typically an oil supply to lubricate the crank shaft…"[58] (emphasis added). The study also only referred to reciprocating engines later in the document, "Additionally, *reciprocating engines* crankcase vents were checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) because blow-by reduces cylinder compression that causes inefficient operation and contributes to unburned and partially burned fuel emissions[59]" (emphasis added). There is no mention anywhere that natural gas turbines were evaluated as a part of this study.

Since the definition of crankcase within this study explicitly states that it is only applicable to reciprocating engines, and the body of the text supports that definition, then natural gas turbine crankcase vents were not evaluated as part of this study. It is arbitrary to use 2.28 scf/h per crankcase vent for natural gas turbines because turbines were not evaluated for this study.

Natural gas turbines are inherently different from reciprocating engines and quantifying crankcase venting in the manner proposed does not make sense.

A reciprocating engine is a cyclic operation by nature - the piston is required to stroke back and forth inside the cylinder to complete four primary process strokes: intake, compression, power, and exhaust. The piston moves back and forth inside the cylinder of a reciprocating engine, using the piston rings to seal process gas inside the cylinder during the combustion process. This piston is connected to the crankshaft, which translates the reciprocating movement from the combustion in the cylinder to rotational movement at the output shaft. Any leakage across the piston rings will result in combustion gas in the crankcase, which needs to be vented to avoid condensation, contamination, and ongoing reliability concerns. The piston rings act as a primary seal between the combustion process and the atmosphere, and the crankcase takes on the role of a rudimentary "capture" system.

Gas turbines operate using a completely different mechanical method. There is no cyclic or reciprocating element to a gas turbine operation (no piston, piston rings, or crankcase). A gas turbine uses one (or more) rotating shafts to continuously complete all four primary combustion functions inside the gas turbine casing: intake, compression, combustion, and expansion. Since the shaft(s) are already rotating as part of the combustion process, there is no requirement to have a translation from reciprocating to rotational movement, so there is no crankshaft or crank casing to be vented. Combustion gases are ultimately routed to the atmosphere by way of the exhaust duct once the power turbine has extracted the energy. The potential leakage points for combustion gases would be at the turbine casing flanged connections or at the shaft seals, which are addressed by other parts of this rulemaking (fugitive emissions).

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[57] Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites. EPA Phase II Aggregate Site Report prepared for U.S. EPA Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc. March 2006. Available at https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.

[58] Page 14 of 74 of API study.

[59] Page 40 of 74 of API study.

The Industry Trades propose that natural gas turbines not be included for reporting crankcase venting, as there are no crankcase vents on the natural gas turbines.

3.16 Gathering and Boosting versus Production Site Categorization

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves designation of upstream operators' centralized tank batteries that EPA has named "centralized oil production sites." These are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility." In the proposed rule, EPA has classified centralized oil production sites under the gathering and boosting segment.

The Trades appreciate that EPA has recognized centralized production sites as a facility type in the proposed rule. However, there are challenges and environmental disincentives with including "centralized oil production sites" in the gathering and boosting segment, especially when viewed through the lens of the upcoming waste emissions charge.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the gathering and boosting segment. These sites perform many of the same functions as the traditional well pad only production facilities (which are included in production), but reduce the overall environmental footprint associated with oil and gas development included emissions reductions and minimizing surface use by flowing multiple wells into on pad.

Next, EPA's proposed definitions are contrary to IRA's MERP waste emissions thresholds, where gathering and boosting sites are considered "non-production." In the MERP language, (f) Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production." The Gathering and Boosting segment (segment #8) is explicitly listed under "Non-Production." Clearly Congress did not intend for sites associated with production, such as "centralized production sites" to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the gathering and boosting segment in the past but for application of the fee, these sites should be considered production. Doing otherwise would result in an inequitable application of the fee that would most likely not be applied uniformly by all upstream operators.

EPA's proposal to group its proposed new definition of "centralized oil production site" within the "gathering and boosting" category, *see* 88 Fed. Reg. at 50,437/1, is inconsistent with the text and structure of CAA § 136. Congress defined "production" and "gathering and boosting" as two distinct items in a list of eight parallel categories of applicable facilities subject to the MERP charge, CAA § 136(d)(2) ("Onshore petroleum and natural gas production"), (8) ("Onshore petroleum and natural gas gathering and boosting"). EPA is therefore acting contradictory to this text and to Congress's intent when it proposes to categorize *production* facilities as *gathering and boosting* ones. And this mis-categorization will have consequences, because the waste emissions threshold above which a charge will be imposed on applicable facilities' emissions differs between these two categories, *see id.* § 136(f)(1), (2

The proposed definition of "centralized oil production site" is also inconsistent with the proposed definition and regulatory treatment of a "centralized production facility" in the pending CAA § 111 methane standards proposal for both new and existing sources.

In addition, the categorization of a centralized production site into gathering and boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane fees that may accompany categorizing production sites as gathering and boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installation dramatically increasing the amount of equipment in the field, increasing GHG emissions, and increasing surface use.

Further, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to "production supportive facilities." Many operators have migrated to more centralized production facilities in an effort to reduce the overall environmental footprint. As opposed to midstream operators that traditionally operate gathering and boosting sites downstream of a custody transfer meter that are typically large compressor stations that boost gas across an area, the sites in question are a less impactful way of separating and storing fluids from multiple wells and providing efficient compression for artificial lift. Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment typically results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, are considered in the industry as part of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as "associated with a single well pad" this has created a great deal of confusion with reporters and centralized tank batteries have been categorized differently both by individual owners / operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb/c regulations, the "centralized oil production facilities" (referred to in NSPS OOOOb as "centralized production facilities") are grouped under the production segment by definition, not gathering and boosting as explained below:

> *Currently, in Subpart W "Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236."*

While NSPS OOOOb/c has a different name and definition of this as follows:

> *"Centralized production facility" means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage*

> *vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."*

In addition, in the Pipeline and Hazardous Material Safety Administration's ('PHMSA") proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate any production facilities as "gathering and boosting." Specifically, as defined in API's Recommended Practice-80 and incorporated in 49 CFR 192:

> *"The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. 'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."*

Both the NSPS OOOOb/c and PHMSA's name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. To mitigate confusion and create more rule alignment, the Industry Trades suggest that EPA align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/c.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal,

> *"as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." Also, the Trades note that even though EPA uses the word "gather" in the definition in Quad Ob/c, these sites are still properly defined as "part of the producing operations."*

Further, the fact that EPA has proposed the definition of "centralized production sites" as sites that do not include compressors that are part of the gathering and boosting segment is puzzling. If these sites are part of the gathering and boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the gathering and boosting segment on them? This demonstrates that EPA possibly does understand the distinction between gathering and boosting compressors that should appropriately be included in the gathering and boosting segment and centralized tank batteries that clearly should not.

As such, The Industry Trades request that EPA change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production (not gathering and boosting) for consistency and to reflect how the industry owns and operates these facilities. The Trades also strongly recommend that EPA delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

3.17 Need for EPA to Include Pathways for Other Types of Empirical Data

For many source categories under Subpart W, the Trade Industries appreciate that EPA has included several options for operators to be able to provide empirical data, such as measurement with metering or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. As API shared with EPA during the NSPS OOOOb and OOOOc rulemaking, many operators have included these technologies in their voluntary methane management programs, including the use of quantitative aerial technologies at more than 8,000 sites. Many of these systems provide quantitative information that, when paired with other operational sources of data, provide empirical information about methane emissions from assets. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. **A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.**

4. Administrative Recommendations

4.1 Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors

Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.

1. EPA should provide industry with a draft of the eGGRT form for review ahead of the reporting season (prior to January 1, 2026). The Industry Trades are concerned that the site-by-site reporting could cause these files to become very large and difficult to transmit and/or store.
2. EPA has not indicated how Best Available Monitoring Methods (BAMM) will be allowed for the newly proposed sources. The Industry Trades reiterates the need for ample implementation time.
3. Remove all requirements to report a count of equipment or events when there is a requirement to report on an equipment- or site-level basis. Requiring a count of an item that is already provided on a line-by-line basis does not improve the reported data quality, does not increase EPA's ability to validate the reported data, and introduces potential errors that will flag unnecessary follow between reporters and EPA.
4. Remove or automate Table AA.1.ii on Tab (aa)(1). All the required information is reported in Table AA.1.iii. By repeating this information in Table AA.1.iii, it increases the possibility of data errors while not improving data transparency.
5. Remove detailed reporting elements on Tab (aa)(1) in Table A.1.iii, as the detailed information on a well-by-well basis is already included on the respective source tabs (and proposed additional sources as part of this rulemaking):
    a. Well venting for liquids unloading;
    b. Completions or workovers with hydraulic fracturing;
    c. Completions or workovers without hydraulic fracturing;

    d. Well testing; and
    e. Associated gas venting and flaring.
6. Miscellaneous Topics
    a. Reporting condensate separate from other hydrocarbon products will be challenging due to where and how it is separated.

5. Rule Implementation

EPAs plans to finalize the rule in August 2024, with an implementation date of January 1st, 2025. The impractical tight timeframe to implement the final rule places an unrealistic expectation on reporters, especially given that (as proposed) they will have to install new equipment and develop inspection programs to comply with the rule. The impracticality of the proposed timeline is further exacerbated by the persistent supply chain shortages operators are experiencing for critical equipment necessary to comply with the proposed NSPS OOOOb, as the Industry Trades have described to EPA.[60] Primarily, the Industry Trades reiterates its position that measurement, sampling and monitoring requirements should not be included in the GHGRP itself. However, should any measurement, sampling and monitoring requirements be codified in Subpart W for sources not required to comply with other regulatory programs, EPA should allow for a phase-in period (as it did during the first two years of Subpart W implementation) to allow for reporters to incorporate those requirements.

6. Conclusion

The undersigned associations, representing the oil and natural gas industry, appreciate EPA's willingness to collaboratively engage with the regulated community in order to improve the quality and consistency of reported data while also streamlining the reporting process. The comments provided in this letter are intended to support this effort by providing EPA with additional context and potential unintended consequences associated with some of the proposed measurement, reporting, recordkeeping, and quality assurance/quality control requirements.

The Industry Trades support the goal of reducing GHG emissions across the value chain of the oil and natural gas industry, and it is critical that the EPA and the GHGRP reflect accurate reporting of GHG emissions. To that extent, it is important that EPA carefully consider these proposed revisions and new subparts and consider the points outlined by the Industry Trades while considering future proposed rulemaking.

The undersigned associations encourage EPA to carefully consider the comments and recommendations contained within this letter. We stand ready to respond to any questions and provide further clarifications, as needed, from EPA. Please do not hesitate to contact any of the undersigned or API's Jose Godoy, Climate & ESG Policy Advisor, at godoyj@api.org.

Sincerely,

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[60] https://www.api.org/news-policy-and-issues/letters-or-comments/2023/09/20/API-Letter-to-EPA-Administrator-Regan-on-EPA-Methane-Rule.

Aaron Padilla

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Angie Burckhalter
Sr. V.P. of Regulatory & Environmental Affair
The Petroleum Alliance of Oklahoma

Leslie Bellas

Leslie Bellas
Vice President
American Fuel & Petrochemical Manufacturers

CC: Chris Grundler, Director for Office of Atmospheric Programs, EPA
Mark DeFigueiredo, Office of Atmospheric Programs, EPA

ANNEX A: API Study, “Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States.

Note: Data for this study is included separately within this docket in excel format.

Memorandum

Date: July 2, 2020

To: Mark DeFigueiredo, Melissa Weitz, Adam Eisele

Climate Change Division, U.S. Environmental Protection Agency

From: Karin Ritter, Manager, Corporate Policy, American Petroleum Institute

Re: American Petroleum Institute Pneumatic Controller Measurement Study

The American Petroleum Institute (API) is pleased to provide the results of the API Field Measurement Study of Pneumatic Controllers and API's proposal for a two-tiered emission factor for controllers. Paul Tupper (Shell), on behalf of API, presented preliminary information from this study at the Stakeholder Workshop on GHG Data for Natural Gas and Petroleum Systems held in Pittsburg PA on November 7, 2019. This was followed with an API and EPA conference call on January 13, 2020 where API provided answers to EPA's questions regarding the study results and details (attached).

As a reminder, the API field study found that the average emission rate for properly functioning intermittent controllers was 0.28 scfh, 24.1 scfh for malfunctioning intermittent controllers and an overall average emission rate for all intermittent controllers of 9.3 scfh. Continuous low bleed controllers had an average emission rate of 2.6 scfh and continuous high bleed controllers 16.4 scfh. Malfunctioning intermittent pneumatic controllers measured in the API study account for about 85% of observed pneumatic controller emissions, from all controllers measured, and 98% of the observed intermittent pneumatic controller emissions. About 38% of the intermittent pneumatic controllers in the study were determined to be malfunctioning although a small subset of the malfunctioning controllers contributed the bulk of measured emissions.

The results of the API field study pneumatic controller measurements are consistent with prior studies (Allen et al. 2015, Thoma et al. 2017) which found that a small number of malfunctioning intermittent controllers accounted for the bulk of pneumatic controller emissions measured. Based on the results of the API study, API proposes that EPA modify 40 CFR Part 98 Subpart W to include a two-tier intermittent pneumatic controller emission factor option for intermittent pneumatic controllers that are included in a qualified inspection and repair program. This would be similar to the leaker emission factor option currently in Subpart W for equipment leaks. Specifically, API is proposing a properly functioning intermittent pneumatic controller whole gas emission factor of 0.28 scfh, and a malfunctioning intermittent pneumatic controller emission factor of 24.1 scfh. These emission factors would be applied to intermittent pneumatic controllers included in a qualified inspection and repair program. Intermittent pneumatic controllers not included in a qualified inspection and repair program would continue to use the current emission factor of 13.5 scfh. A qualified inspection and repair program would require instrument (optical gas imaging (OGI)) inspection of intermittent pneumatic controllers on a minimum annual frequency to determine whether they have continuous emissions which would indicate that they are malfunctioning. The tiered emission factor could be used by operators that voluntarily include intermittent pneumatic controllers in an inspection and repair program or that are required to include them by regulation or other requirement. Such an approach would enable demonstration of emission reductions by operators who are voluntarily conducting pneumatic controller inspections and repair and potentially incentivize further voluntary inspections to identify malfunctioning pneumatic controllers. It would also improve the accuracy of emissions reported into the Greenhouse Gas Reporting program for intermittent pneumatic controllers and ultimately could be used to improve the accuracy of estimated emissions in the Greenhouse Gas inventory. API is not proposing any changes to the emission factors for continuous bleed controllers at this time.

API notes that OGI inspection of intermittent pneumatic controllers to determine if they are properly functioning or malfunctioning is the technique used by EPA and the Colorado Department of Public Health and Environment (CDPHE) in their recently published study "Understanding oil and gas pneumatic controllers in the Denver–Julesburg basin using optical gas imaging". API also suggests that EPA may wish to include data from prior studies (Allen et al. 2015, Thoma et al. 2017) to calculate a set of tiered emission factors from a wider dataset.

Enclosed with this memo are an API paper titled "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States", an excel file with data tables for the study, and API's responses to EPA's questions received prior to the January 13, 2020 conference call. Should you have any questions regarding this study or API's tiered emission factor proposal please feel free to contact me.

Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States

Introduction

EPA's current Greenhouse Gas Reporting Program (GHGRP) emission factor for natural gas-driven intermittent vent pneumatic controllers represents an average emission rate of 19 pneumatic controllers, 7 measured in the US and 12 measured in Canada during two field campaigns in the 1990's (EPA, 1996). The 7 US pneumatic controllers had an average emission rate of 21.3 standard cubic feet per hour (SCFH) with a range of 8.8 to 39.6 SCFH. The 12 Canadian pneumatic controllers had an average emission rate of 8.8 SCFH with a range of 0.5 to 29.0 SCFH. Combined, these 19 intermittent pneumatic controllers had an average emission rate per intermittent pneumatic controller of 13.5 SCFH. The small total sample size (19 measurements) and high variability of the measurements suggests that the EPA mandated average emission factor of 13.5 SCFH warrants reevaluation.

Several pneumatic controller emissions studies conducted since then have focused on emission factor development or comparisons with existing factors based on field observations (Allen et al. 2013, Allen et al. 2015, Thoma et al. 2017, Prasino Group 2013). These studies observed a skewed distribution of emissions largely related to emissions from intermittent pneumatic controllers with higher than expected emissions for properly functioning controllers. Allen et al. (2015) found that 95% of observed emissions were attributable to 19% of pneumatic controllers and noted that the majority of the 40 highest emitting controllers were behaving in a manner inconsistent with manufacturer design. Thoma et al. (2017) also concluded that emissions were dominated by malfunctioning pneumatic controller systems, although the absolute emission rates observed were lower than with Allen et al.

The American Petroleum Institute (API) conducted a pneumatic controller measurement study between June and April 2016. Study goals included creating a pneumatic controller inventory for the regions surveyed, classifying pneumatic controllers, understanding the frequency of pneumatic controller malfunctions, and quantitatively measuring emission rates. The analysis presented in this report focuses on the quantitative measurements of intermittent vent pneumatic controllers, where the controllers are sub-classified as either properly functioning or malfunctioning intermittent pneumatic controllers. Emission factors are derived by sub-category, akin to the leak emission factor for fugitive components (US EPA, 2017). Overall, malfunctioning intermittent vent pneumatic controllers measured in the API study account for about 85% of observed pneumatic controller emissions and 98% of the observed intermittent vent pneumatic controller emissions.

Materials and Methods

Pneumatic Controller Inventory

Pneumatic controllers were inventoried at 67 sites[1] operated by 8 companies, across a variety of site types in the production and gathering and boosting segments of the oil and natural gas sector. The sites represented a variety of production and formation types, including conventional and unconventional oil and gas plays, across four basins as defined by the American Association of Petroleum Geologists (AAPG): Anadarko (AAPG Basin 360), San Juan (AAPG Basin 580), Gulf Coast (AAPG Basin 220), and Permian (AAPG Basin 430). Pneumatic controllers from these sites were inventoried and classified as either continuous high bleed, continuous low bleed, or intermittent vent pneumatic controllers based upon a combination of manufacturer information, manufacturer technical data sheets, and expert judgement.

Pneumatic Controller Emissions Measurements

Emission rate measurements were collected for controllers at 39 of the 40 sites with natural gas powered pneumatic controllers. For each measured pneumatic controller, the emission rate of whole gas was quantified using a high-volume sampler instrument (see description below). Whole gas emission rates were calculated based upon concentration, flow and equipment-specific hydrocarbon response factors developed from site-specific gas compositions, as provided by participant companies. In some cases, site-specific gas compositions were unavailable. AAPG basin average concentrations were developed from the available site-specific concentrations and applied to those sites in the same basin without site-specific gas concentrations.

Development of the specific instrument configuration and gas composition correction factors were recently described and applied in a companion study that compared the effectiveness of Method 21 and Optical Gas Imaging for monitoring of fugitive components in oil and natural gas operations (Pacsi et. al, 2019). In this study, a custom GHD recording high volume sampler, developed by GHD – the contractor preforming this study, was used for most pneumatic controller measurements. The GHD recording high flow sampler is a modification to the original high flow samplers developed by Indaco. These modifications include the use of a data logger to record the sample flow and the sample gas concentration at approximately 1/2Hz. Due to instrument availability, there were 8 instances where an Indaco high volume sampler was used for the pneumatic controller measurement and one instance where the Bacharach high volume sampler was used. Three of the 9, measured with the Indaco or Bacharach high volume samplers, had zero measured emissions, while the remaining six measured constant emission rates.

Sampling, over an approximate 15-minute period, occurred through a nozzle affixed to a sampling bag. The sampling bag was fitted over the emission point of the pneumatic controller allowing ambient air to comingle with the source emissions. The recording high volume sampler was equipped with a pump which pumped ambient air and hydrocarbons from the emission point through the nozzle to the flow

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[1] Five sites in the Permian Basin were not inventoried due to being primarily CO_2 or instrument air for the pneumatic controller supply gas.

meter and concentration detection instrument. The combustible gas concentration instrument, a Bascom-Tuner Gas Rover, measured combustible gas concentrations via one of two detectors: either a combination catalytic oxidation (0-5% hydrocarbon gas) or a thermal conductivity (5-100% hydrocarbon gas) detector. Further information on the instrument detail is available in the Supplemental Information from the companion equipment leaks study (Pacsi et. al, 2019) and references such as Lamb et al. (2015) and Thoma et al. (2017).

Properly functioning intermittent vent pneumatic controllers have near-zero emission rates between actuation cycles. Also, the volume of vented gas associated with controller actuations can vary widely from pneumatic controller to pneumatic controller. With the wide variation of emissions and high frequency of non-detect measurements in this and prior pneumatic controller measurement studies, it was prudent to develop a conservative field detection limit estimate for this study to facilitate appropriate interpretation of zero or near zero field measurements. The instrument methane detection limit for the GHD recording high volume sampler was determined to be 0.009 SCFH based on the lowest flow recorded during pneumatic controller testing and the methane detection limit of the Bascom-Turner Gas Rover (50 ppm) used in the GHD recording high volume sampler. However, in field use the instrument resolution was coarser than the instrument's minimum detection limit.

The GHD recording high volume sampler instrument operates with variable flow rates. Accordingly, the instrument detection thresholds and instrument resolution varied over the course of the study in terms of resolvable emissions rates since both the emission rate detection limit and instrument resolution is a function of measurement flow rate. An effective resolution for each non-zero time series was calculated as the minimum of the absolute value of the differences between adjacent elements of a given time series. This represents the minimum measured emission rate difference from one measurement to the next in each time series. The derived minimum effective resolution provided an estimate of the minimum resolvable emission rate for this study.

Figure 1 shows the effective resolutions for 127 of the time series measurements (non-zero time series for intermittent vent pneumatic controllers that varied over the course of the approximately 15 minute measurement). The median value of effective resolution for the 127 time series measurements is 0.26 SCFH, with approximately 70% of the measurements having an effective resolution between 0.2 and 0.35 SCFH. Therefore, an effective resolution over the course of the study was empirically determined to be 0.26 SCFH.

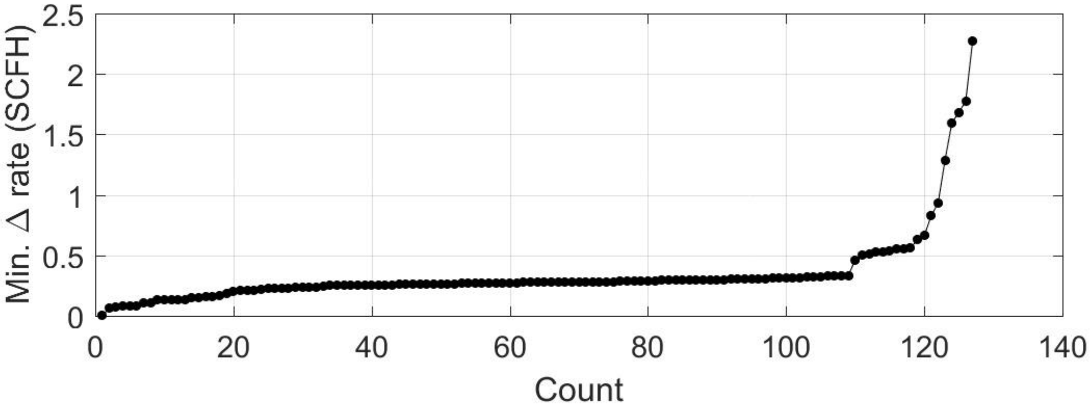


Figure 1: Instrument resolution step sizes for the recorded time series.

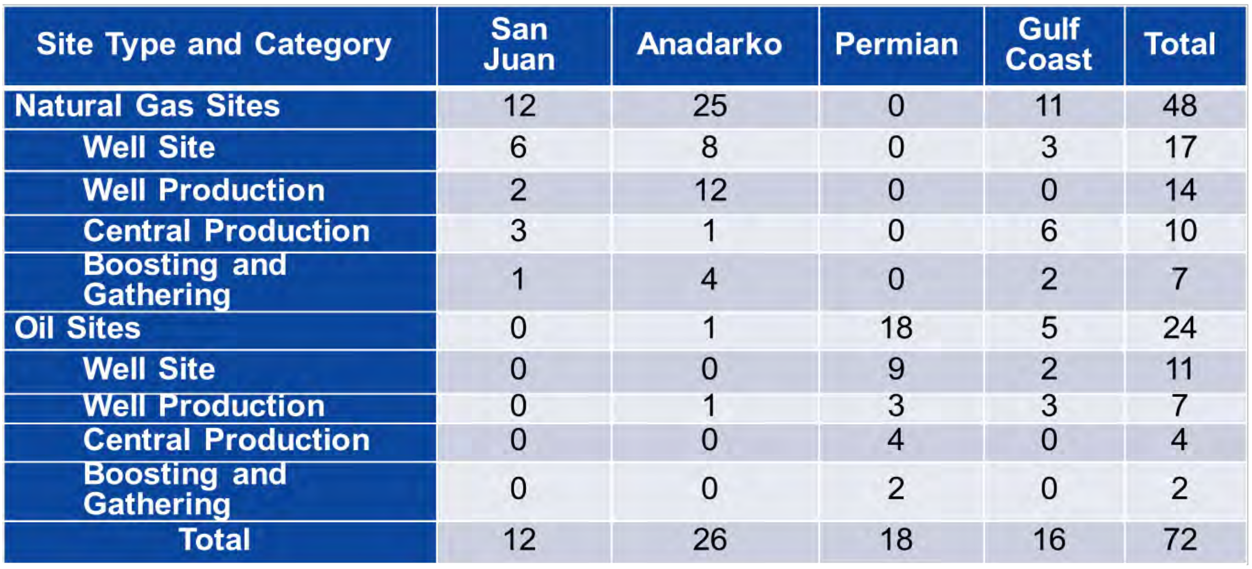
Approximately 45% of measured emission rate values of the intermittent vent pneumatic controllers were less than half of the effective resolution, and a large number had zero measured emissions. Thoma et al. (2017) previously described a "seepage rate" assumed to be on the order of 0.05 SCFH from properly functioning intermittent vent pneumatic controllers due to the practical limitations of metal to metal seals under real world conditions. Accordingly, low level emissions could have been occurring during field measurements in this campaign although the instrument recorded a low or zero value due to instrument resolution limitations.

Therefore, measured emission data points below half the effective resolution of 0.26 SCFH were conservatively assumed to be 0.13 SCFH. Thus, the minimum instantaneous emission rate within any intermittent vent pneumatic controller emission rate time series was assumed to be 0.13 SCFH for all analyses. In addition, an actuation was assumed to have taken place where the instantaneous emission rate exceeded 0.39 SCFH, indicating a clear episodic emission larger than 1.5 times the effective resolution and thus distinguishable from noise (actuation threshold).

Pneumatic Controller Inventory and Classification

A total of 72 sites were selected for the study. Table 1 tabulates the distribution of site type and category by basin.

Table 1: Site type and category for the four sampled basins*



Site Type and Category	San Juan	Anadarko	Permian	Gulf Coast	Total
Natural Gas Sites	12	25	0	11	48
Well Site	6	8	0	3	17
Well Production	2	12	0	0	14
Central Production	3	1	0	6	10
Boosting and Gathering	1	4	0	2	7
Oil Sites	0	1	18	5	24
Well Site	0	0	9	2	11
Well Production	0	1	3	3	7
Central Production	0	0	4	0	4
Boosting and Gathering	0	0	2	0	2
Total	12	26	18	16	72

*For a complete description of the site categories see: Table S1 of Pacsi, AP, et al. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth, 7: 29. DOI: https://doi.org/10.1525/elementa.368

Controllers at 67 sites were inventoried, including 45 with pneumatic controllers present and 19 sites without non-mechanical controllers. Of the 45 sites with pneumatic controllers present, 40 sites had one or more pneumatic controller powered by natural gas[2], four sites had pneumatic controllers exclusively powered by CO_2 and one site had pneumatic controllers exclusively powered by air. Detailed inventories of the controllers at the 45 sites with pneumatic controllers resulted in the identification of 420 controllers. The set of 420 controllers included 370 powered by natural gas, 39 powered by air or CO_2, seven powered electrically, and four out-of-service or with unknown power source. The natural gas powered pneumatic controllers were further classified into the three EPA categories (US EPA, 2014a): 1) intermittent vent; 2) continuous low bleed (<=6 SCFH) or 3) continuous high bleed (>6 SCFH) pneumatic controllers. Pneumatic controllers lacking sufficient detail to classify between intermittent or continuous service were labeled as "unclassified" (Figure 2).

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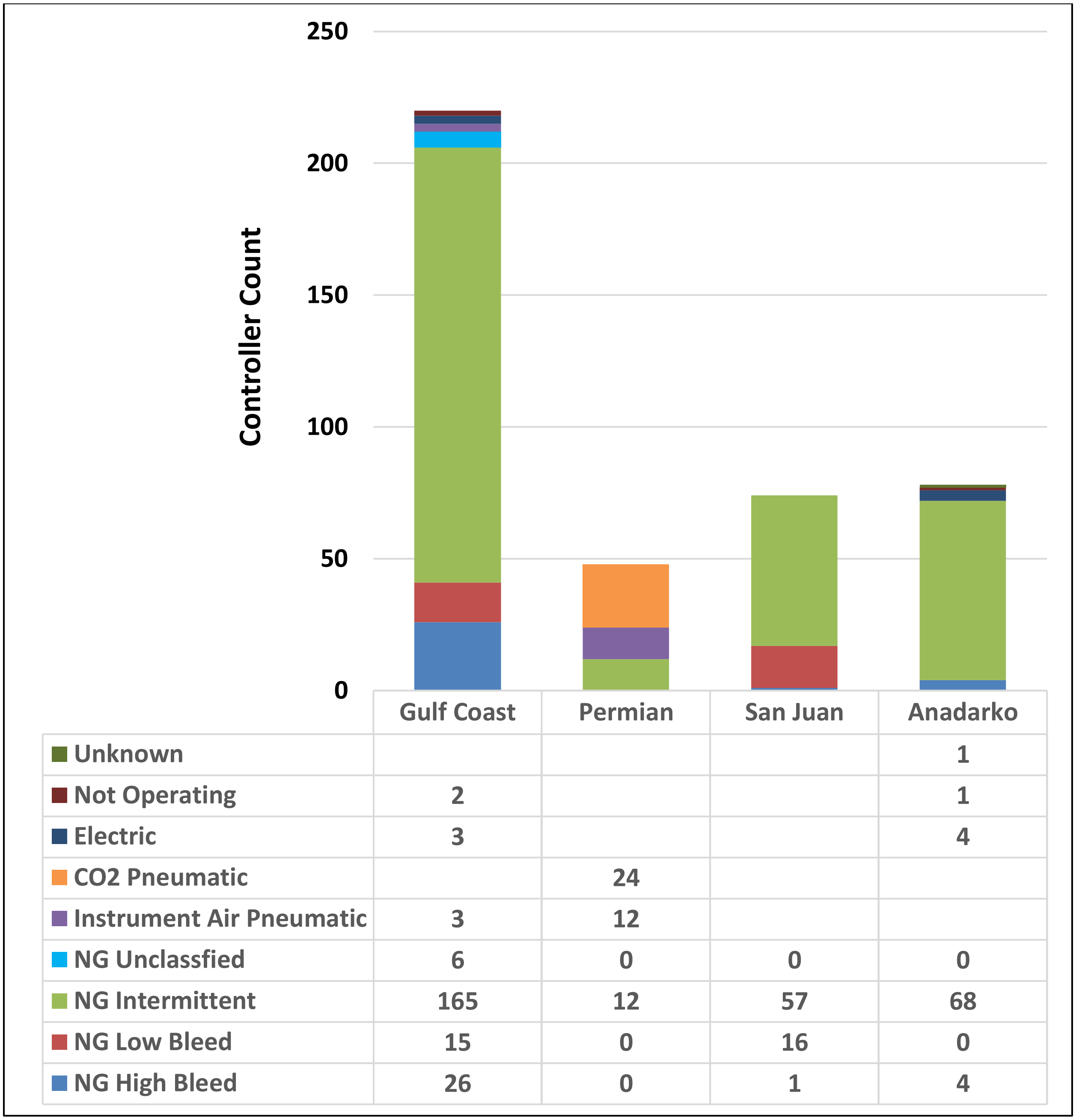
[2] Natural gas in the context of this study is inclusive of field gas, sales gas, processed gas, and other types of predominantly methane gas. The term excludes gas streams that were predominantly CO_2 or compressed air.



	Gulf Coast	Permian	San Juan	Anadarko
🟩 Unknown				1
🟥 Not Operating	2			1
🟦 Electric	3			4
🟧 CO2 Pneumatic		24		
🟪 Instrument Air Pneumatic	3	12		
🟦 NG Unclassfied	6	0	0	0
🟩 NG Intermittent	165	12	57	68
🟥 NG Low Bleed	15	0	16	0
🟦 NG High Bleed	26	0	1	4

Figure 2: Inventory of pneumatic controller types by basin.

The majority of inventoried natural gas-powered controllers were intermittent vent controllers. as shown in Figure 2. The Permian basin sites in this study generally used either mechanical, instrument air or CO_2 operated pneumatic controllers, resulting in a small number of natural gas-powered pneumatic controllers at those sites.

Pneumatic Controller Emission Measurements

Project time constraints only allowed for emission measurements on a subset of inventoried controllers. Exhaust emissions were measured from 308 natural gas powered pneumatic controllers at 39 sites. The vast majority of measurements were conducted using a GHD recording high-flow type instrument with readings predominantly captured at about two second sample rates over a measurement period of approximately 15 minutes. Controller meta-data was collected for each pneumatic controller measured. The meta-data included manufacturer, model number, type, service and photos. Each controller measured was classified into one of the US EPA's regulatory types: intermittent vent, continuous vent low-bleed bleed, or continuous vent high-bleed. The majority (85%) of the pneumatic controllers measured were intermittent vent type which is broadly consistent with the overall inventory for this study as shown in Figure 3. [3]

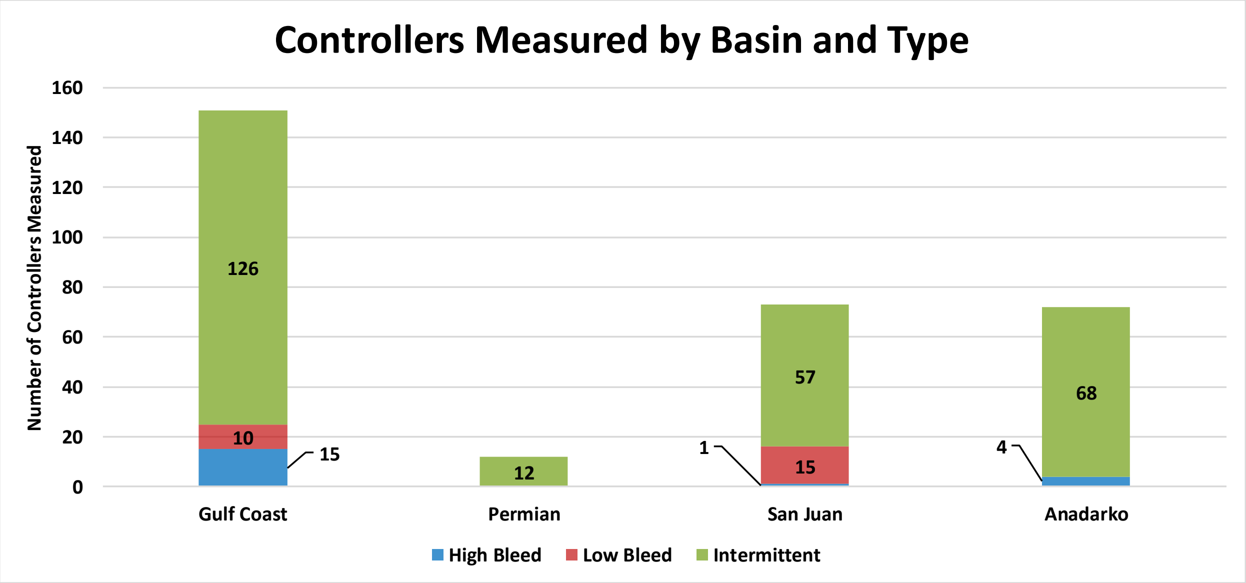


Figure 3: Number of pneumatic controllers measured by EPA type and basin.

Previous studies have reported pneumatic controller emission results on an average emission rate per controller basis. For this study, average emission rates by basin and controller type are shown relative to US EPA Subpart W emission factors (Figure 4, Table 2), however they should be interpreted with caution. Basin-level average emission rates for both continuous vent, high and low bleed types are limited by small sample sizes. Although the sample size of the intermittent vent pneumatic controller measurements is larger, intermittent vent controllers are analyzed by the subcategories of properly functioning and malfunctioning which reduces the sample size in each subcategory.

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[3] Three of the controllers measured and classified as intermittent vent controllers are listed as displacement tanks for wastewater/oil by the manufacturer and differ from the typical understanding of intermittent vent controllers. However, they were retained in the study reports and statistics.

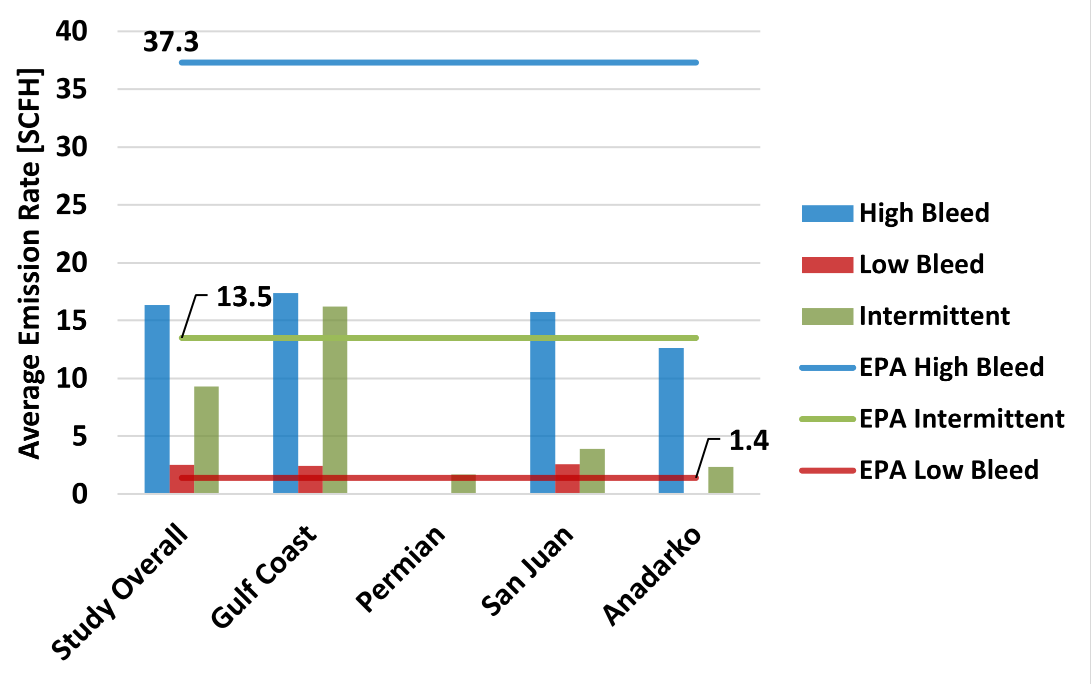


Figure 4: Average emission rates per controller by type and basin compared to US EPA Subpart W emission factors.

Table 2: Average emission rates per controller by type and basin in SCFH.
ND indicates that no measurements were made for the type of controller within the basin.

	Study Overall	Gulf Coast	Permian	San Juan	Anadarko
All Controllers	9.2	15.4	1.7	3.7	2.9
High Bleed	16.4	17.4	ND	15.7	12.6
Low Bleed	2.6	2.7	ND	2.6	ND
Intermittent	9.3	16.2	1.7	3.8	2.3

The intermittent vent pneumatic controller average emission rate for all measured intermittent vent pneumatic controllers represents the average emission rates of properly functioning and malfunctioning controllers. Actions taken to minimize the number of malfunctioning pneumatic controllers, such as a proactive monitoring and repair program, may result in a reduction in the number of malfunctioning intermittent controllers and thus reduce emissions. Emission factors were derived by the properly functioning and malfunctioning sub-categories, akin to leak/no-leak factors applied to fugitive components (US EPA, 1995). For the overall study, malfunctioning intermittent pneumatic controllers (~38% malfunction rate in this data set) contributed about 98% of the observed intermittent pneumatic controller emissions.

Intermittent Vent Pneumatic Controller Emissions Analysis

In this study, 263 intermittent vent pneumatic controllers were measured. The 120 resultant time series with no instantaneous measurements greater than 0.39 SCFH (1.5 times the effective resolution, the assumed actuation threshold) were considered minimally emitting. Emissions with data above the actuation threshold were observed in the remaining 143 time series. Any individual instantaneous measurement in the time series below 0.13 SCFH (1/2 the effective resolution of 0.26 SCFH) was replaced with a value of 0.13 SCFH.

Based on the observed time series, pneumatic controllers were classified as either properly functioning or malfunctioning. Minimally emitting time series were a subset of properly functioning time series where no actuations were observed. Properly functioning intermittent pneumatic controller time series were those characterized by either distinct, episodic actuations, with a clear return to a baseline of 0.13 SCFH in between actuations, or with consistently *de minimis* emission rate (< 0.39 SCFH – actuation threshold of 1.5 times the effective resolution). Time series from malfunctioning intermittent pneumatic controllers typically showed continuous emissions with no return to baseline. Examples of a properly functioning intermittent pneumatic controller (top panel) and a malfunctioning intermittent pneumatic controller (bottom panel) are show in Figure 5.

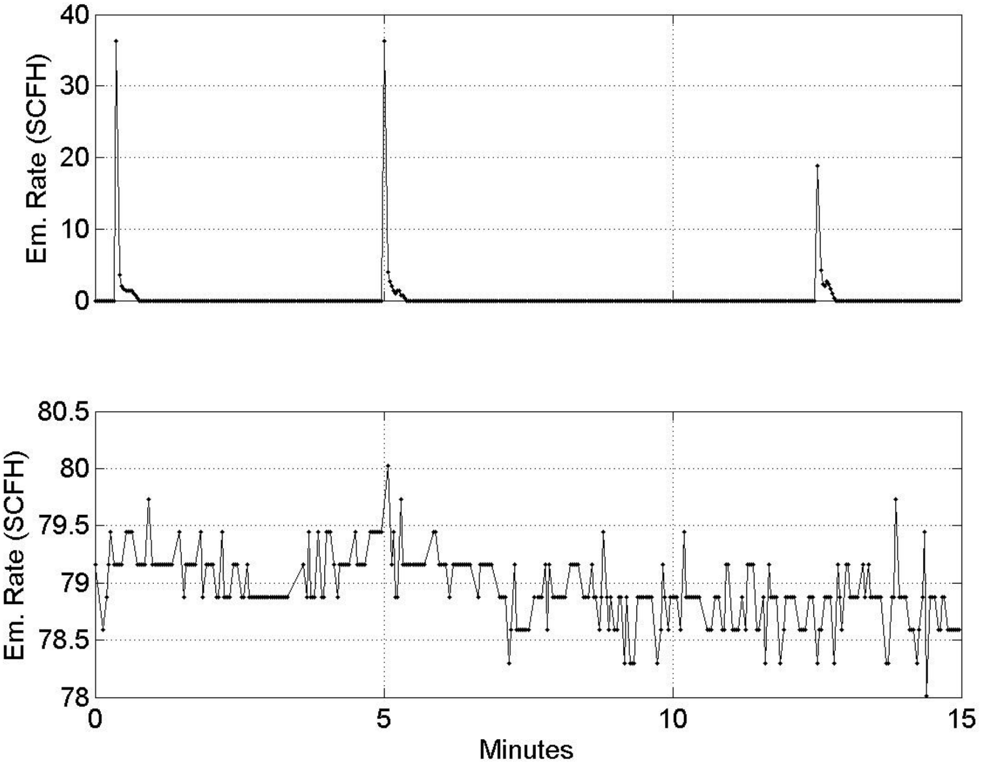


Figure 5: Top panel: Properly functioning intermittent vent pneumatic controller (the baseline level is 0.13 SCFH). Bottom panel: Malfunctioning intermittent vent pneumatic controller.

The following algorithm was developed to provide a consistent basis for classification as described below.

Intermittent vent controllers were classified as properly functioning where:

1. The median emission rate was less than 0.39 SCFH
2. Greater than 25% of a time series had an emission rate less than 0.39 SCFH
3. All individual actuations lasted less than 180 seconds (~20% of the measurement duration)

Otherwise, the pneumatic controller was classified as malfunctioning.

The third criterion above is based on the expectation that actuations should occur over a limited duration with a return to a low level value. The 3 time series that failed this criteria had unexpectedly prolonged actuations indicative of a malfunctioning intermittent controller (*i.e.*, such as the bottom panel in Figure 5). Automated classifications were visually confirmed based upon engineering judgment.

The automated algorithm for determining if an intermittent pneumatic controller is properly functioning or malfunctioning used here is specific to this dataset because it is based on the minimum effective resolution of the dataset. The algorithm can potentially be adapted for use on other datasets based on their minimum effective resolution, but this should be verified prior to its implementation.

Average emission rates for each of the intermittent vent controllers were calculated (Table 3). Of the 263 total time series analyzed, 120 were minimally emitting. Of the 120 minimally emitting intermittent controllers, 11 had an average emission rate greater than 0.13 SCFH but less than 0.39 SCFH with a mean value of 0.21 SCFH, giving an average overall emission rate of 0.137 SCFH for all 120 minimally emitting intermittent pneumatic controllers. An additional 44 were classified as properly functioning with a mean emission rate of 0.66 SCFH for a total of 164 properly functioning intermittent pneumatic controllers with a mean emission rate of 0.28 SCFH. An additional 99 intermittent pneumatic controllers were malfunctioning with a mean emission rate of 24.1 SCFH. The average emissions per controller for all 263 intermittent vent controllers was 9.25 SCFH.

Table 3: Average emission rates per intermittent controller by type in SCFH.

	Average Emission Rate (SCFH)
Properly Functioning	0.28
Malfunctioning	24.1
All Intermittent	9.25

Actuation Frequency Sensitivity Analysis

Pneumatic controllers that were observed as minimally emitting during the study were expected to actuate on some frequency despite not having been observed over the course of this study. A sensitivity case was evaluated to assess the maximum potential error in the average emission rate based upon a conservative scenario assuming the measurement team had just missed an actuation. The sensitivity case assumed each of the minimally emitting pneumatic controllers actuated every 20-minutes with an actuation volume equal to the average emission volume per actuation of the properly functioning, but not minimally emitting, pneumatic controllers (0.02 SCF per actuation). The average emissions per controller for all 263 intermittent pneumatic controllers increased by ~0.1 % from 9.25 SCFH to 9.26 SCFH under this scenario. Thus, unaccounted for actuations of properly functioning controllers, even at a very high actuation rate, had a minimal effect on the total emissions which is consistent with sensitivity analyses in Allen et al. (2015).

Intermittent Pneumatic Controller Population Distributions

Cumulative distribution functions (CDFs) were fitted to the data to facilitate visualization of the relative populations (properly functioning vs. malfunctioning across regions). Weibull CDFs were fitted to the average emission rate data. Figure 6 shows the CDFs fitted to emission rates for the malfunctioning and properly functioning intermittent pneumatic controllers, respectively. Minimally emitting controllers were omitted from the fitting procedure because fitting a continuous distribution to data that contains a large number of non-unique data points leads to poor distribution fits. Those data were added back into the probability distribution plots (Figures 7 and 8).

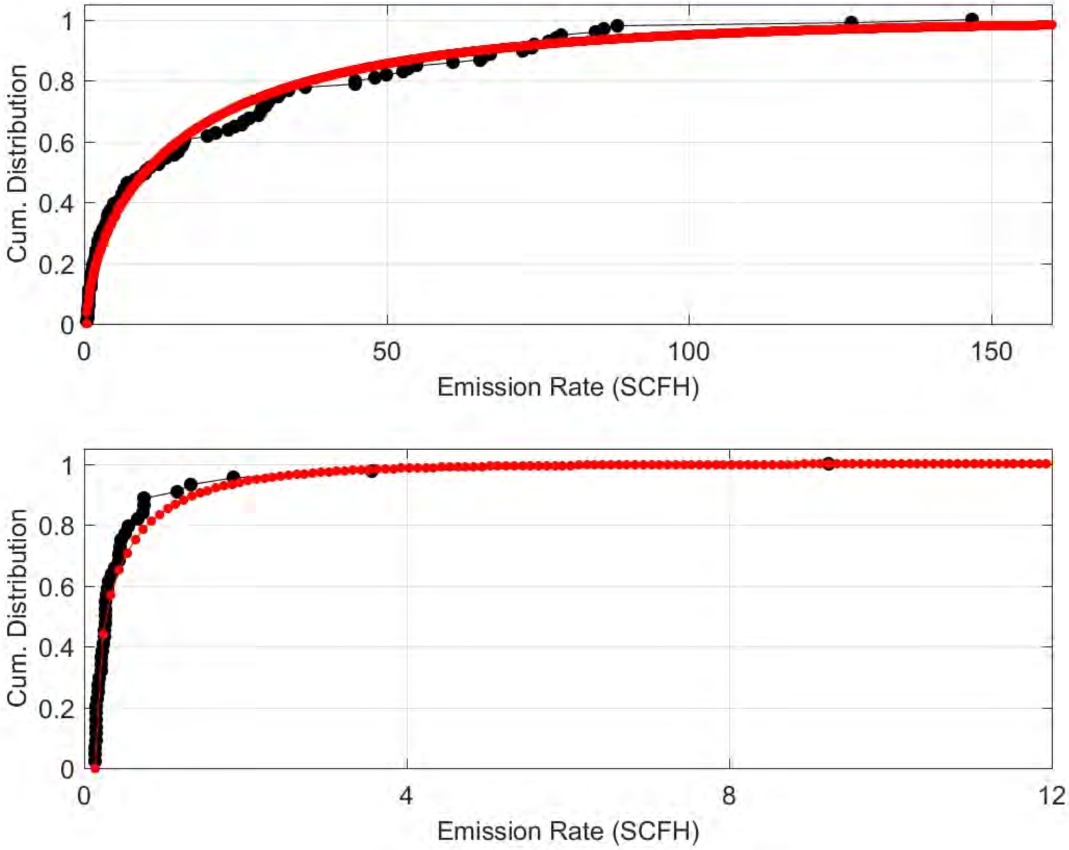


Figure 6: Top panel: Malfunctioning intermittent pneumatic controller emission rates (black circles) with fitted CDF (red line). Bottom panel: Properly functioning intermittent pneumatic controller emission rates (black circles) with fitted CDF (red line) excluding minimally emitting data.

Table 4: Parameters of the Weibull CDF distributions fitted to the malfunctioning and properly functioning data (excluding minimally emitting).

	Weibull scale parameter	**Weibull shape parameter**
Properly functioning	0.2735	0.5463
Malfunctioning	17.4266	0.6294

The relative contribution of emissions as a function of emission rate for properly functioning and malfunctioning intermittent vent pneumatic controllers, including minimally emitting pneumatic controllers, is shown in Figure 7. The malfunctioning intermittent controllers account for about 98% of the measured emissions from intermittent vent controllers. The primary driver of emissions in this dataset are the highest emissions from malfunctioning intermittent vent pneumatic controllers. The top 15 pneumatic controller emission rates (15 of the 263 or ~5.7 %), which were malfunctioning and emitting at a rate of at least 60 SCFH, account for about 51% of the emissions from all 263 intermittent pneumatic controllers.

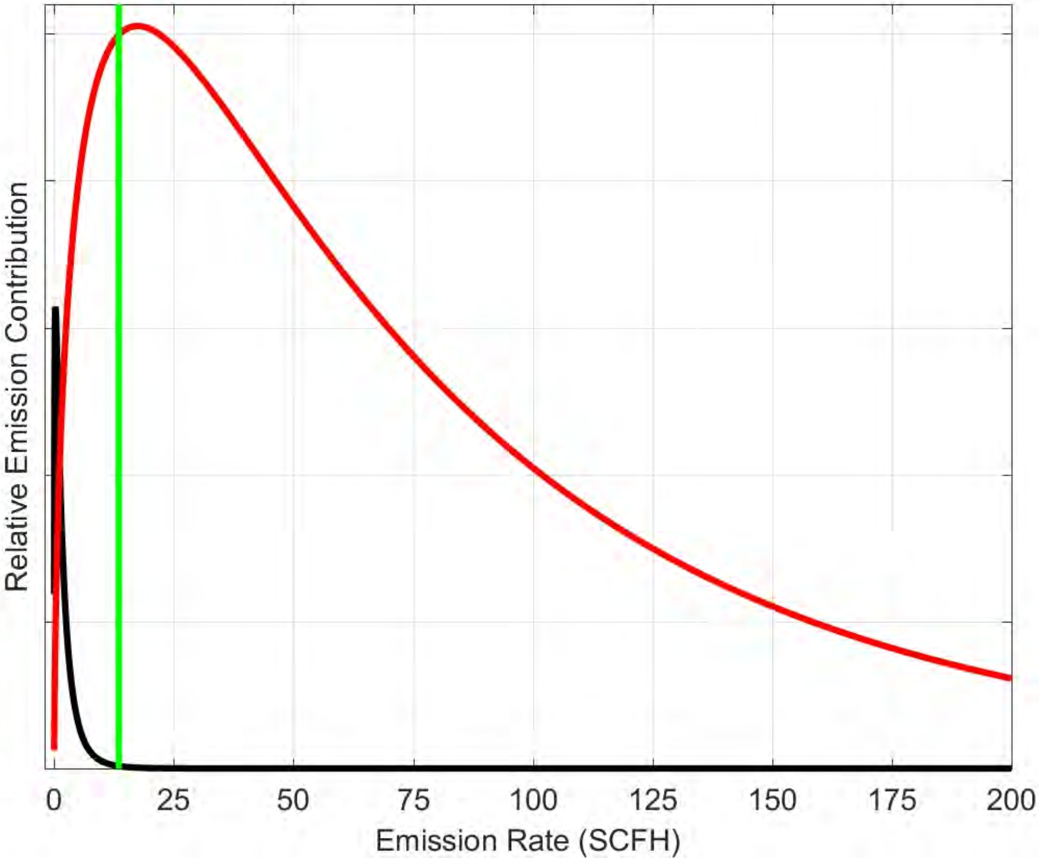
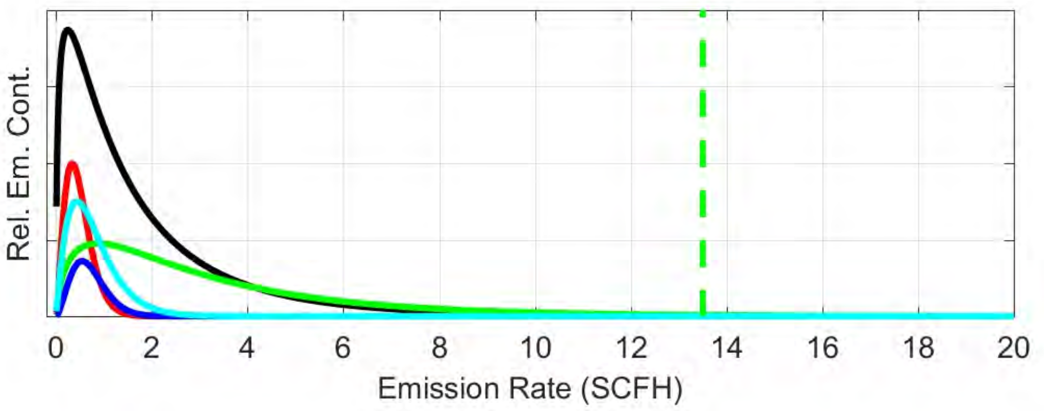


Figure 7: Relative contribution of properly functioning intermittent pneumatic controllers including minimal emitting controllers (black line), malfunctioning intermittent pneumatic controllers (red line), and the Subpart W intermittent vent pneumatic controller emission factor (green line).

A similar analysis was performed on the subsets of data for each of the four basins included in this study. The relative contributions of emissions for each region as a function of emission rate for properly functioning and malfunctioning pneumatic controllers, including minimally emitting pneumatic controllers, are shown in Figure 8, while Table 5 provides the Weibull scale and shape parameters for the fits. Note that there was only one malfunctioning pneumatic controller in the Permian basin so a fit was not possible.



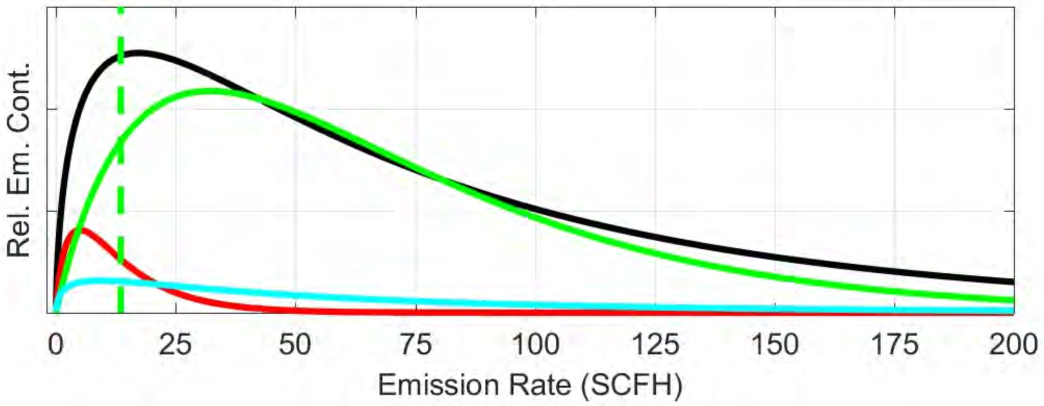


Figure 8: Top panel: Relative contribution of emissions for properly functioning intermittent pneumatic controllers, including minimally emitting controllers, by basin. Bottom panel: Relative contribution of emissions for malfunctioning intermittent pneumatic controllers by basin.

For both panels: The black line represents all the data (Figure 8). The red line represents the Anadarko basin, the green line represents the Gulf Coast basin, the blue line represents the San Juan basin. The green dashed line represents the Subpart W intermittent vent pneumatic controller emission factor.

Table 5: Weibull distribution parameters for properly and malfunctioning pneumatic controllers for the four basins.

Basin	Weibull scale parameter	Weibull shape parameter
Properly Functioning		
Anadarko	0.3377	1.3425
Gulf Coast	0.8784	0.7180
Permian	0.5451	1.5642
San Juan	0.4349	1.0913
Malfunctioning		
Anadarko	5.0269	0.8210
Gulf Coast	32.9045	0.9568
Permian	---	---
San Juan	9.1526	0.5492

Emission Factor Development

The Gulf Coast basin contributed the largest number of emitters and volume of emissions to the malfunctioning intermittent controller category as well as total emissions in this study. The Gulf Coast basin had 13 of the 14 top emitting intermittent pneumatic controllers. The remaining top emitting malfunctioning intermittent pneumatic was located in the San Juan basin. Excluding the single top emitter for the San Juan basin drops the mean emission rate value per malfunctioning intermittent controller for the San Juan basin from 17.4 SCFH to 7.5 SCFH and also significantly alters the Weibull scale parameter in the CDF fit for malfunctioning intermittent pneumatic controllers in the San Juan basin from 9.1526 to 5.6217. This illustrates the sensitivity of the pneumatic controller emission rate to the distribution of properly functioning and malfunctioning intermittent pneumatic controllers.

The skewed distribution of emissions, where a small number of malfunctioning intermittent pneumatic controllers accounted for the majority of measured emissions, suggests that a malfunctioning pneumatic controller monitoring and repair program may be effective in reducing emissions far below the current emissions estimates. Many operators report that they voluntarily practice such an inspection program in locations where the company is already performing leak detection and repair inspections. Unfortunately, there is no opportunity to demonstrate the reductions that such a program achieves because Subpart W requires the application of a single factor in the tabulation of intermittent vent pneumatic controller emissions irrespective of whether the controller is functioning properly or malfunctioning.

Table 6 shows the detectable portion of this study's measured emissions under different detection threshold scenarios. Malfunctioning intermittent vent pneumatic controllers emitting at a rate > 2 SCFH (an emission rate likely detectable with an optical gas imaging camera) account for about 97.6 % of the total emissions based upon the intermittent vent pneumatic controllers measured in this study. For a threshold of 10 SCFH, which may be detectible by audio-visual-olfactory (AVO) monitoring, about 92.3% of the emissions could potentially be located and significantly reduced.

Table 6: Specified detection threshold, the number and percentage of malfunctioning intermittent pneumatic controllers emitting above that threshold, as well as the percentage of total intermittent vent controller emissions represented by malfunctioning controllers emitting above the specified threshold.

Detection Threshold (SCFH)	# of Intermittent pneumatic controllers	% of Intermittent pneumatic controllers	Detectable % of Total Intermittent Controller Emissions
2	78	29.6	97.65
4	66	24.6	96.04
6	61	22.7	95.05
10	51	19.3	92.30
25	35	13.3	81.78
50	19	7.2	59.97
75	8	3.0	31.51
100	2	0.8	11.25

A stratified emission factor approach (e.g. Table 3) could be applied to intermittent pneumatic controllers to account for properly functioning and malfunctioning controllers. The approach is analogous in design to application of leaker emission factors for equipment leaks in Subpart W when an OGI leak inspection program is in place. Such an approach would enable demonstration of reductions by operators who are voluntarily conducting pneumatic controller inspections and potentially incentivize further voluntary inspections to identify malfunctioning pneumatic controllers.

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ANNEX B: API Comments on Proposed Subpart W, Submitted July 21, 2023

July 21, 2023

<u>Submitted electronically to docket No. EPA-HQ-OAR-2019-0424</u>

Jennifer Bohman
Climate Change Division, Office of Atmospheric Programs (MC-6207A)
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Docket No. EPA-HQ-OAR-2019-0424

Dear Ms. Bohman:

The American Petroleum Institute, the American Exploration & Production Council, Independent Petroleum Association of America, The Petroleum Alliance of Oklahoma, and the Offshore Operators Committee (collectively "Industry Trades") appreciate the opportunity to offer comments to the U.S. Environmental Protection Agency (EPA) on the proposed “Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule” (proposed on May 22, 2023). With this submittal, the Industry Trades seek to continue our participation in the rulemaking process as a collaborative stakeholder by providing meaningful solutions to address EPA’s goals while addressing the burden of data collection (and identifying potential unintended consequences) that could result if the rulemaking is finalized as proposed.

We have participated as key collaborative stakeholders throughout the process of developing the EPA Greenhouse Gas Reporting Program (GHGRP) by contributing expertise and proposing solutions that address EPA's policy goals while reflecting the reality of the industry and its evolving day-to-day operating practices. The Industry Trades have directed our efforts toward seeking a balance between the burden of data collection and reporting, the need to protect sensitive information and ensure that reporting requirements are placed on the correct reporters, and the need for providing the highest quality data that will help inform decision makers and the public.

These comments reflect our continued interest in the evolution of the GHGRP to provide an accurate accounting of greenhouse gas (GHG) emissions from facilities across the full value chain of the oil and natural gas industry. Our comments cover concerns and recommendations in the wide range of sectors that relate to the operations of our collective members.

INDUSTRY TRADES' INTERESTS

The American Petroleum Institute (API) is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader convening subject matter experts from across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 800 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Additionally, API has a history of working with EPA to refine and improve data collection, emission estimation and emission reporting under various subparts of the GHGRP. API has worked with both EPA and the regulated industry for more than two decades in developing methodologies for estimating greenhouse gas emissions from oil and natural gas operations. API's first *Compendium of GHG Emissions Methodologies for the Oil and Natural Gas Industry* (the *Compendium*) was published in 2001. As reflected in EPA's efforts to revise the GHGRP and API's recent publication of a 4th edition of the *Compendium (November 2021)*, our abilities to estimate and measure greenhouse gas emissions are continually evolving.

The American Exploration & Production Council (AXPC) is a national trade association representing 30 of the largest independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of ensuring positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

The Independent Petroleum Association of America (IPAA) represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The Petroleum Alliance of Oklahoma (The Alliance) represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. The Alliance's members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas and play an essential role in providing products and solutions to improve human health and welfare, power the global economy, and make modern life possible. Abundant, clean-burning natural gas has enabled the United States to become the global leader in greenhouse gas emissions reductions. The Alliance's members have and will continue to deploy technologies that result in meaningful greenhouse gas emission reductions through innovative solutions and breakthrough technologies while meeting the energy demands of today and the future.

The Offshore Operators Committee (OOC) is an offshore energy trade association that serves as a technical advocate for over 90% of the companies operating on the U.S. Outer-Continental Shelf (OCS). Founded in 1948, the OOC has evolved into the principal technical representative regarding regulation of offshore energy operations. Our members include operators and service providers working to ensure safe production of offshore energy for the workforce and the environment.

Industry Trades' Comments on EPA's "Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule"

Docket ID No. *EPA-HQ-OAR-2019-0424*

1. Introduction

The Industry Trades support efforts to improve accuracy and enhance consistency between regulatory programs as it relates to greenhouse gas (GHG) reporting. The comments provided herein reflect feedback from the Industry Trades on the proposed changes to the GHGRP for subparts impacting the oil and natural gas industry, with a particular focus on the newly proposed Subpart B's burdensome reporting and recordkeeping requirements as well as potential unintended consequences resulting from these requirements. The Industry Trades are respectfully submitting comments on the following subparts:

- Subpart A – General Provisions
- Subpart B – Energy Consumption
- Subpart C – General Stationary Fuel Combustion
- Subpart P – Hydrogen Production
- Subpart Y – Petroleum Refineries
- Subpart PP – Suppliers of Carbon Dioxide
- Subpart UU – Injection of Carbon Dioxide
- Subpart WW – Coke Calciners

As presented in Sections 2 and 3 below, the Industry Trades' comments are organized by proposed amendments to current subparts and proposed new subparts, respectively.

2. Comments on Proposed Amendments to 40 CFR Part 98

1. Subpart A – General Provisions

a. The Industry Trades support EPA's proposal to update the Global Warming Potentials (GWPs) for calculating CO_2-equivalent (CO2e) emissions of non-CO_2 gases (CH_4, N_2O, HFCs, PFCs, SF_6, and NF_3) to reflect updated estimates contained in the Intergovernmental Panel on Climate Change's (IPCC's) Fifth Assessment Report (AR5), based on a 100-year time horizon. We agree with EPA's proposal to use the 100-year GWP for methane. The proposed GWP changes to Table A-1 in Subpart A are aligned with the Inventory of U.S. Greenhouse Gas Emissions and Sinks [i.e., the U.S. EPA GHG Inventory (GHGI)] and complies with the United Nations Framework Convention on Climate Change (UNFCCC) decision to use GWP values from the IPCC AR5 in national reporting by countries by the end of 2024.

   While the Industry Trades agree with the proposed revisions to the GWPs included in Subpart A, the Industry Trades request that EPA clarify in the preamble to this proposed rulemaking the impacts on the reported total CO_2e emissions due to changing the GWP (particularly for methane), without any actual change in mass emissions. With an increased focus on methane emissions from the oil and natural gas industry, it is important to inform stakeholders that future increases in CO_2e emissions due to the change in GWP are not reflective of any actual mass emission increases. Likewise, the Industry Trades recommend that the EPA acknowledge that combustion CO_2e emissions will be impacted from both the reduction in N_2O GWP, as well as the increase in CH_4 GWP.

2. Subpart C – General Stationary Fuel Combustion

The EPA's proposed revisions include requirements to report emissions from the stationary combustion category that result from an electricity generating unit (EGU) and to report an estimated fraction of total emissions from a multi-unit group of combustion sources under 40 CFR 98.36(c) attributable to EGUs. The preamble to the supplemental proposed rule states that "some manufacturing facilities, such as petroleum refineries and pulp and paper manufacturers, operate stationary combustion sources that generate electricity. Reporting of an EGU indicator for these units would allow the EPA to assign the emissions from any electricity generating units at the facility more appropriately to the power plant sector."[1]

a. An EGU is not specifically defined within Subpart A or Subpart C; the definition of an "electricity generation source category" EGU found in Subpart D in 98.40 includes only EGUs that are subject to monitoring and reporting requirements found in 40 CFR Part 75. While EGUs are not defined in Subpart A explicitly, a footnote to Table A-7, "Data Elements that Are Inputs to Emission Equations and for Which the Reporting Deadline is March 31, 2015" states that for sources reporting under Subpart C (cited below with **emphasis added**). The Industry Trades are seeking clarification on the definition of an EGU for this reporting element; as proposed, it is unclear what units would meet this reporting requirement. The Industry Trades support a definition that aligns with the footnote presented under Table A-7:

   Required to be reported only by: (1) Stationary fuel combustion sources (e.g., individual units, aggregations of units, common pipes, or common stacks) subject to subpart C of this part that contain at least one combustion unit ***connected to a fuel-fired electric generator owned or operated by an entity that is subject to regulation of customer billing rates by the PUC (excluding generators connected to combustion units subject to 40 CFR part 98, subpart D) and that are located at a facility for which the sum of the nameplate capacities for all such electric generators is greater than or equal to 1 megawatt electric output;*** *and (2) stationary fuel combustion sources (e.g., individual units, aggregations of units, common pipes, or common stacks) subject to subpart C of this part that do not meet the criteria in (1) of this footnote that elect to report these data elements, as provided in § 98.36(a), for reporting year 2014.*

   Additionally, the Industry Trades propose that the definition of an EGU specifically exclude drivers used to power equipment including but not limited to compressors and pumps.

b. The Industry Trades also propose that the EPA provide clarification and flexibility to 98.34(e), which references 98.34(d) to determine the biogenic portion of CO_2 emissions. Since gaseous fuels can be sampled prior to combustion for biogenic content and used to determine the biogenic portion of CO_2 emissions, the Industry Trades propose the following additional language (***in red***) to provide options to use other approved sampling standards or industry standard practices:

   "(e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, *e.g.,* tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866-16 and ASTM D7459-08 (both incorporated by reference, see §98.7) may be used to determine the biogenic portion of the CO_2 emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. ***As an alternative to ASTM D7459-08 and paragraph (d), an entity may also use a method published by a consensus-based standards organization, if such a method exists, or you***

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[1] 88 Fed. Reg. at 32873.

may use industry standard practice. The method(s) used shall be documented in the GHG Monitoring Plan required under 98.3(g)(5). If the primary fuel for multiple units at the facility consists of tires, and the units are fed from a common fuel source, testing at only one of the units is sufficient."

c. In the proposed revisions to Subpart C, EPA should move all combustion calculations and reporting requirements from Subpart W to Subpart C in order to avoid confusion in reporting natural gas combustion emissions, as previously articulated in the Industry Trades' comments submitted on October 6, 2022.[2]

d. Additionally, site-specific CH_4 emission factors may be available for certain equipment from the equipment manufacturer or from acceptable testing methodologies. EPA should allow for the use of site-specific CH_4 emission factors as an alternative to the CH_4 emission factors in Tables C-2 or Table W-9, with the following proposed addition (below, ***in red***) to 98.33(c)(1) through 98.33(c)(4). Required use of generic factors disincentivizes reporters to mitigate and reduce methane emissions. This change would also be consistent with the recently proposed updates to 40 CFR Part 98, Subpart W.

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH4 emission factor from Table W–9 to subpart W of this part, ***Table C-2, or site-specific emission factors****.*

3. Subpart P – Hydrogen Production

In general, this subpart proposes to include all facilities that produce a hydrogen product(s) including non-merchant hydrogen production process units previously reported under Subpart Y (Petroleum Refineries) and captive plants, but excludes reporting of catalytic reforming units. EPA also proposes that the associated steam consumption for these units and their fuel usage previously reported under Subpart C (Combustion) be reported under Subpart P.

a. The Industry Trades support the exemption to the source category in 40 CFR 98.160(b)(1)(B) clearly excluding catalytic reforming units covered under Subpart Y from reporting in Subpart P.

b. The Industry Trades do not support amending the source category requiring reporters to report combustion from hydrogen production process units under Subpart P in lieu of Subpart C as proposed in 40 CFR 98.160(c). These units may not be metered separately from other combustion units located at an integrated facility such as a refinery with a hydrogen production unit; therefore, we recommend reporting stationary combustion emissions from hydrogen production under Subpart C. If those emissions have to be reported under Subpart P instead of Subpart C, EPA shall allow engineering estimation for fuel consumption to avoid burdensome retrofitting of fuel meters.

c. The Industry Trades are also concerned that reporting the net quantity of steam consumed as proposed under 40 CFR 98.166(b)(9) could result in duplicative reporting based on what is proposed to be reported under Subpart B (i.e., where steam is provided by a third-party supplier). The Industry Trades respectfully request removal of this requirement from Subpart P.

d. EPA is seeking comment as to how to determine when or how a source will trigger or cease to report under Subpart P. EPA is proposing to use hydrogen production rates as the trigger for GHG reporting, instead of direct GHG emissions. EPA believes this approach will capture hydrogen production units which use energy (rather than

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[2] API comments to EPA's proposed GHGRP Rule, October 6, 2022.

fossil fuel combustion). The Industry Trades believe that these types of units will frequently be part of a larger operation already subject to GHG reporting, and energy consumption will be captured under Subpart B.

The Industry Trades offer the following recommendations on the provisions to cease reporting:

i) Hydrogen production process units which produce hydrogen but emit no direct GHG emissions should become eligible to cease reporting starting January 1 of the following year after the cessation of direct GHG emitting activities associated with the process;

ii) If the direct GHG emissions remain below 15,000 MT CO2e or between 15,000 and 25,000 MT CO2e, the Industry Trades recommend that reporting would be required for 3 or 5 years respectively, aligned with the existing Part 98 reporting off-ramp provisions; or

iii) If EPA establishes a hydrogen production threshold for reporting, then the Industry Trades recommend that falling below that production threshold should be the trigger for cessation of reporting, either starting January 1 of the following year or on a parallel structure to the 3- and 5-year off-ramp emission thresholds.

The Industry Trades recommend that if the hydrogen production unit continues to combust fuel or is part of a larger process with multiple (or comingled) combustion units, those emissions will continue to be reported under Subpart C, consistent with the Industry Trades' recommendation above. Similarly, if the process unit is part of a refinery, any non-combustion energy consumption related to the process unit will be captured under proposed Subpart B.

e. EPA is seeking input on requiring sales information for hydrogen production. There are several reasons the Industry Trades believe this should not be required unless proposed through a separate rulemaking process.

  i. First, it is important to note that the hydrogen market is in its very early stages, and it is unknown how hydrogen for energy consumption may evolve in the near or longer term. Codifying this in the regulation will require a full regulatory rulemaking process to address changing market conditions. As this market is evolving, it is possible this proposed new GHGRP requirement will become overly burdensome without providing useful information.

  ii. Second, this information is considered "Confidential Business Information" (CBI) by both the seller and/or the buyer and may be restricted by confidentiality provisions in sales contracts; therefore, it should not be publicly reported.

  iii. Finally, it is not clear how this information would be used by EPA; information necessary to determine emissions intensity is already provided in Subpart P.

If EPA disagrees with the recommendations above, the Industry Trades recommend limiting the reporting requirement to include only bulk hydrogen sales quantities, without specifying individual buyers identities and sales quantities. If reporting sales information is required, the Industry Trades recommend reporting at corporate level, rather than individual transactions, and that a cut-off threshold for reporting be established, similar to Subpart NN.

4. Subpart Y – Petroleum Refineries

Proposed revisions to Subpart Y include deletion of the reference to non-merchant hydrogen production plants and to coke calcining units as these are being addressed in Subparts P and WW, respectively. Additionally, EPA is proposing to include a requirement to report the capacity of each asphalt blowing unit.

The Industry Trades support the removal of reporting requirements for non-merchant hydrogen production plants in Subpart Y, and instead report these units under Subpart P. Likewise, the Industry Trades support the reporting of coke calcining units in the newly added Subpart WW.

EPA's rationale for requesting the capacity of each asphalt blowing unit is not clear to the Industry Trades, nor is it clear how this data would be used. t is unclear how the individual capacity data will support more accurate reporting. With the additional data collection and reporting requirements, the Industry Trades would like to better understand EPA's reasoning for requesting this information, so that we can recommend the most appropriate and effective data to meet EPA's objectives.

5. Subpart PP – Suppliers of Carbon Dioxide

As proposed, reporters would be required to report the facility identification number associated with the annual GHG reports for each Subpart RR and VV facility to which CO_2 is provided. Additionally, EPA is seeking comment on whether to expand the reporting requirements for all receivers of CO_2, not just those facilities subject to Subparts RR and VV.

a. The Industry Trades support EPA's efforts to increase accuracy in tracking supplies of CO_2 in the economy, but request EPA to analyze whether both senders and receivers of CO_2 reporting is redundant.

b. The Industry Trades also recommend that EPA provides additional information on how CO_2 suppliers for export could appropriately address exports in their report. For example, clarity in reporting is needed to address situations in which a company supplies CO_2 to a non-reporter that is a subsidiary of a larger company that does report.

c. EPA is seeking comment on further expanding the list of end-use applications reported in 40 CFR 98.426(f) to better account for and track emerging CO_2 end uses. Similar to our comments under Subpart P, the market for CO_2 utilization continues to develop. As such, the Industry Trades are recommending EPA allow, in this rulemaking, flexibility in how this information is reported by allowing reporters the ability to select from a representative range of end-uses, including allowing for instances when the end-use is 'other'. The Industry Trades believe that this information could be captured in EPA's forms and updated as needed to account for innovation in this emerging market.

6. Subpart UU – Injection of Carbon Dioxide

The Industry Trades support EPA's efforts to increase clarity and reduce the potential for double counting of reported emissions. In addition, the Industry Trades support EPA's proposal to revise the proposed text in 40 CFR 98.470(c) from "are not required to report" to "shall not report."

3. Comments on Proposed New Source Categories to Part 98

1. Subpart B – Energy Consumption

This newly proposed subpart will require those reporters that are already subject to reporting under existing provisions in 40 CFR Part 98 to:

- Report the quantity of purchased electricity and thermal energy products;
- Develop a Metered Energy Monitoring Plan (MEMP), which includes identifiers for each meter (including photographs), accuracy specifications, manufacturer's certifications, and other details;
- Keep documentation of quality assurance for purchased electricity monitoring including documentation that meters are conforming with appropriate ANSI standards;
- Keep documentation of quality assurance for purchased thermal energy including copies of the most recent audit of the accuracy of each meter in the purchasing agreement, and if the audit is more than 5 years old, documentation of a request for a new audit to the energy provider (and auditing the meter every 5 years); and
- Report multiple pieces of information for every bill for every purchased energy product meter, as well as requiring submittal of representative billing statements for each purchasing agreement.

The Industry Trades believe many of the provisions within the proposed regulation are extremely burdensome for geographically disparate operations such as those found in the oil and natural gas industry and focus our comments on the unique challenges associated with the meter-level recordkeeping and segment level reporting. In general, the Industry Trades believe there are ways to provide energy consumption information to EPA in a way that achieves EPA's policy goal while not imposing overly burdensome requirements to energy purchasers. Specifically, the Industry Trades recommend EPA to:

- Allow energy purchasers subject to reporting under Subpart W to report energy consumption for all Subpart W activities within a single AAPG hydrocarbon basin;
- Generally, remove meter-level recordkeeping and reporting requirements for the purchaser of energy. If required, any such meter-level requirements should be provided by the electricity supplier as the owner/operator of the meters;
- Remove meter-level QA/QC requirements from the energy purchaser, and instead require energy providers to ensure meters meet required accuracy requirements as the owners of the equipment;
- Exempt Subpart B reports from the "Substantive Error" provisions found in Subpart A; and
- Remove the requirement for a separate MEMP plan, but instead allow reporters to augment existing GHG recordkeeping procedures in the Greenhouse Gas Monitoring Plan (as required in 40 CFR 98.3(g)(5), with additional requirements in subsequent subparts), to include backup documentation, procedures, QA/QC methodologies and other supporting data. This information would be available upon request by EPA.

The following commentary is provided as context to these recommendations.

The proposed recordkeeping, QA/QC and reporting requirements as proposed in this supplemental rulemaking are extremely burdensome for oil and natural gas operations and could result in disincentivizing site electrification. For the oil and natural gas operations that cover a large geographical area consisting of numerous assets, such as onshore oil and gas production and onshore gathering and boosting where the facility encompasses assets across an entire American Association of Petroleum Geologists (AAPG) basin, the number of energy providers and the number of individual meters can be quite significant. For example, in the Permian Basin, a medium-sized upstream operator could have more than 5,000 individual well sites and tank batteries across more than 70,000 square miles and could have hundreds if not thousands of energy meters. Some operations in Alaska and North Dakota have very limited timeframes during which weather would allow for the proposed meter-specific data collection efforts (e.g., meter photos, meter numbers, etc.). Providing documentation on a meter-by-meter basis, including billing statements, would result in an extremely burdensome reporting process, requiring uploading billing statements for hundreds, if not thousands, of meters for individual reporting entities. This is an excessive reporting requirement given that it is likely that the vast majority of meters used in the upstream oil and natural gas segment are for very small energy consuming sites, are not owned or operated by the energy purchaser, and do not serve a specific purpose beyond the reported values. Additionally, imposing these extremely burdensome recordkeeping, reporting and QA/QC requirements for energy purchasers could ultimately result in disincentivizing site electrification, which would be in contrast to the current Administration's drive toward electrification.

Separating energy consumption between reporting segments (e.g., onshore production versus gathering and boosting or gas processing) will be particularly challenging for large integrated operations. The Industry Trades recommend allowing operators subject to Subpart W reporting to report all energy consumption for all reportable Subpart W operations within a single AAPG hydrocarbon basin. Many oil and natural gas operators in the U.S. report both onshore production and gathering and boosting within the same basin and across multiple basins. The proposed data requirements under Subpart B would represent a significant and burdensome data collection effort to not only collect the meter-level data for these multi-asset facilities, but to also then separate the data between the onshore production, gathering/boosting and other GHG reporting segments. In many instances, it is not as simple as a single meter serving a single facility or reporting segment - there are meters recording data across the entire value chain with overlap between the segments - this further complicates a reporters' ability to divide that energy consumption between reporting segments. The Industry Trades request that EPA allow operators who are subject to reporting under Subpart W to report ALL consolidated energy consumption from Subpart W operations within the AAPG basin. If required to report energy by Subpart W source category (i.e., by segment), the Industry Trades request EPA to allow estimation of energy usage between Subpart W facilities, to account for the need to allocate between different facility types (e.g., onshore production, gathering and boosting, etc.) where meters cover energy use across the value chain.

Meter level identification, auditing, accuracy and QA/QC requirements should not be incumbent upon the energy purchaser; instead, these requirements should apply to the meter owner, which is the energy provider. The Industry Trades are concerned that the monitoring and QA/QC requirements proposed in 40 CFR § 98.24, and the reporting requirements in 40 CFR §98.26, will be particularly burdensome given that many of the proposed accuracy and QA/QC requirements would be the responsibility of the energy purchaser rather than the energy provider, despite the fact the energy purchaser does not own, maintain or control the meters. Placing the responsibility for the proposed data requirements on the energy purchaser is inappropriate because it is the energy providers (such as electric utilities) that own and operate the energy meters and are responsible for their accuracy. Further, it is not uncommon for energy providers to change or replace meters without informing the electricity purchaser; therefore, reporting any meter-specific data supplied by an energy purchaser could become inaccurate without the knowledge of the purchaser. Similarly, the energy purchaser does not have access to documentation that the meters conform to ANSI standards, and likely does not have the ability to request that information from the energy provider.

As proposed, the recordkeeping and reporting requirements in Subpart B require reporting detailed supplemental data not required by any other subpart in the GHGRP, and therefore should not be required here. Reporters are not required to submit this level of documentation for other subparts, but instead follow the recordkeeping requirements codified in 40 CFR and the appropriate subparts. The Industry Trades support that same approach for Subpart B. If EPA requires meter-level reporting, the Industry Trades suggest the requirement for supplying energy meter data should reside with the energy provider, not the purchaser.

The Industry Trades provide additional comments on the following specific aspects of the supplemental proposed rule.

Meter-Level Accuracy Assurance Requirements Should Not Fall Upon the Energy Purchaser

As described above, the Industry Trades believe energy purchasers should not be held responsible for accuracy attestations on behalf of energy providers. If an electricity purchaser does not purchase, maintain or monitor meters used for billing purposes, the burden of demonstrating that the meters meet the accuracy requirements of 40 CFR§ 98.24(b) should not fall upon the electricity purchaser; rather, the electricity provider should be responsible for this demonstration. The Industry Trades respectfully recommend removing the proposed requirements in 40 CFR § 98.24(a)(5) and (b) and requiring energy providers to report these certifications.

Alternatively, the Industry Trades recommend that the certification requirements found in 40 CFR §98.24(a)(5) and (b) should be provided by each electricity provider for all meters in the service area, rather than a certification on a meter-by-meter basis.

Meter-Level Recordkeeping and Reporting Requirements

As proposed, 40 CFR § 98.24(a)(2) requires reporters to collect a meter identifier and a photograph of each meter included in the MEMP. Collecting this information from hundreds or thousands of remote well pads, pipelines, and compressor stations, many of which are unmanned, will be extremely time consuming and ultimately may not be accurate. In many (if not nearly all) instances, and as indicated above, electricity purchasers do not own nor control the meters in use at a site; those meters may be replaced or changed by the energy provider without any notice to the electricity purchaser. Therefore, not only is this requirement extremely time consuming for the reporters, it would also fail to meaningfully improve the quality of reported data and the reported information could become outdated without the knowledge of the reporter.

Additionally, as proposed, 40 CFR 98.26(f) requires operators to report several pieces of data for each meter for each bill received. This requirement will be extremely burdensome while failing to increase transparency in reporting. For the oil and natural gas industry, this could require reporting hundreds, if not thousands, of individual meters. As described above, meters can be changed by the energy provider, with or without the purchaser's knowledge, throughout the course of the reporting period. Such meter changes could result in a Designated Representative (DR) certifying a report that may not be accurate as of December 31st of the reporting period[3]. As these meter numbers can change, requiring electricity purchasers to provide this level of detail does not increase EPA's ability to review or otherwise QA/QC the reported data, while still significantly increasing the burden of reporting on energy purchasers. Finally, the requirement to report meter location information to the county/city level can become very complex for facilities operating across a wide geographical area. The Industry Trades are respectfully recommending the removal of this reporting requirement.

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[3] As required in 40 CFR Part 98.4(e), each Designated Representative signs the following certification statement: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

EPA is also proposing reporters to include a "description of the portions of the facility served by the meter." As described above, this requirement would encompass hundreds of meters across a wide geographical area which could change with or without the purchaser's knowledge. This requirement is also burdensome at complex facilities, such as refineries, which may purchase electricity to supplement on-site electricity generation.

The Industry Trades believe these reporting requirements to be overly burdensome and ultimately do not increase the transparency or quality of reported data.

Submitting Sample Energy Bills

As proposed in 40 CFR §98.26, reporters are required to provide EPA with copies of one direct billing statement from each provider. The Industry Trades are concerned these statements could include confidential business information (CBI) relating to purchase agreements, rates, and thermal energy usage. It is also unclear why EPA needs reporters to submit these records; EPA does not have analogous requirements in other subparts to submit example raw data in the form of bills or invoices to validate the reported data.

Additionally, for operators with a large number of sites across a large geographical area, the proposal could require multiple providers to upload hundreds of pages of billing statements. As a practical matter, users of EPA's Electronic Greenhouse Gas Reporting Tool (EGGRT) have experienced delays in using the system when many reporters are using the system simultaneously; this seemingly simple task could result in very time intensive uploading requirements during a reporting period. Furthermore, as previously mentioned, reporters are not required to submit this level of documentation for other subparts, but instead follow the recordkeeping requirements codified in 40 CFR and the appropriate subparts. The Industry Trades support that same approach for Subpart B.

Allow Subpart W Reporters to Submit All Subpart W Segment's Energy Consumption at a AAPG Hydrocarbon Basin Level

The Industry Trades recommend that EPA allow reporters subject to reporting under Subpart W to report energy consumption for all GHG reporting activities within a single AAPG hydrocarbon basin without direct upload of billing statements. The Subpart W operations are often interconnected, and many operators report under production, gas processing and gathering and boosting segments. In addition, electric meters may service an entire basin, a single site, or multiple sites. In order to report at a source category level as defined in Subpart W, operators would need to allocate metered electricity to a single site and then reallocate back to a segment. This would be extremely burdensome and does not meaningfully improve the quality of reported data. This gives reporters the ability to maintain relevant energy consumption information in existing Greenhouse Gas Monitoring Plans, as already required in 40 CFR 98.3(g)(5) and other relevant subparts. As currently codified, this information would be available upon request by EPA.

Missing or Incomplete Billing Information

It is not uncommon for some billing information to not be finalized for up to six- months or longer. As a result, there could be instances where complete billing information may not be available by the reporting deadline for the complete prior calendar year. The Industry Trades request that EPA allow for the use of best information available or other reasonable estimation methods to estimate partial-year energy consumption when a full calendar year of billing is unavailable.

Renewable Energy Credits and Energy Consumption

As EPA has acknowledged in the preamble to the supplemental proposal, this method of reporting energy consumption does not provide the EPA with information on renewable energy credits (RECs) that allows reporters to net Scope 2 emissions commensurate with purchased and retired RECs. The lack of data collection and transparency on renewable energy attributes may inadvertently disincentivize the purchase of renewable energy altogether. The Industry Trades recommend that in addition to reporting the energy consumption, that EPA allows reporters to voluntarily report the amount of energy that is sourced from retired RECs or a renewable energy purchase agreement. This will provide the public and other stakeholders with a more complete picture of overall GHG emissions intensity.

Annual Data Only

EPA is proposing to collect data for every bill and every meter. For example, if the meter is billed monthly, EPA is requesting monthly data. The Industry Trades recommend that EPA remove any requirements to report data more granular than annual data. It is unclear how EPA could even use monthly purchased energy data to assess facility energy intensity. The onerous reporting requirements proposed in this new subpart indicates that EPA believes it can apply automatic checks to ensure all energy consumption bills are as expected and accounted for, the number of expected bills are reported (billing sequence), and that start dates and end dates align. However, given the wide range of energy providers, facility types, geographic locations and other factors, this assumption is incorrect. Bills are subject to billing corrections, rebills, negative usage bills to handle calibration errors, higher-than-previous usage to correct calibration errors; bills with zero usage to handle payment adjustments, overlapping start and end dates, some bills that cover two months instead of one, meters going into service, meters coming out of service, etc. It will be an enormous burden to report detailed information from every bill, EPA has not justified this effort, and EPA will likely burden reporters with error checking for very typical billing inconsistencies. For all of these reasons, EPA should collect annual data only.

Exempt Subpart B Reports from "Substantive Error" Provisions in 40 CFR Part 98 Subpart A

EPA's definition of "Substantive Error[4]", which would trigger resubmittal of applicable GHG reports, is overly broad for this subpart as it does not have a *de minimis* threshold. There can be adjustments to energy consumption records several months following the closing period of the billing cycle. These adjustments could result in an operator having to re-submit reports previously certified even if the adjustment does not result in a significant change in the reported energy consumption. This is especially problematic for the oil and natural gas industry because of the huge number of meters potentially subject to Subpart B, the large number of meters, adjustments, etc. which may not have a substantive impact on overall energy consumption. The Industry Trades request that EPA does not subject Subpart B reports to the "Substantive Error" provisions, as defined in 40 CFR Part 98 Subpart A.

Purchased Thermal Energy Reporting

As proposed, Subpart B requires reporting metered thermal energy products as well as comprehensive auditing requirements for thermal energy meters.

a. Consistent with the comments above, it is the Industry Trades' position that the purchaser should not be required to provide the most recent accuracy audit; instead, that should fall to the energy provider as the owner of the meter.

b. The Industry Trades object to the proposed requirement that a purchaser must conduct the audit on a thermal meter system where purchasing agreements do not include provisions for periodic audits under 40 CFR 98.24(c). Regardless of who is responsible for an audit on a thermal meter system, the Industry Trades request that EPA

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[4] Substantive error, as defined in 40 CFR 98.3(h) means, "an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified."

clarify minimum requirements to be considered a "qualified metering specialist" under 98.24(c) and any restrictions to using in-house resources (i.e., facility, energy provider, independent resources, etc.).

c. The Industry Trades request flexibility regarding the 5-year audit requirement for purchased thermal energy meters. As proposed, 98.24(c) states that if the audit has not been performed (or is older than 5 years old), the energy purchaser is to request an audit from the energy provider. However, this audit procedure can only be completed during a facility shut-down or plant turnaround. The Industry Trades request that EPA add language that allows for this audit to take place either every 5 years or during the next planned unit shut-down.

d. In 98.24(a)(6) and 98.26(j)(2), EPA is proposing that the reporter be responsible for developing a "clear procedure" and example of how measured data are converted to mmBTU. By putting the onus on the reporter to develop "clear procedures," the potential for a wide range in methods and results exists, thus calling into question the value and necessity of reporting thermal energy consumption. For example, there may be differences in how reporters quantify hot and cold energy products (i.e., positive vs. negative value), based on the purpose to add or remove thermal energy. As a result, some reporters may net thermal energy while others sum the absolute values, leading to very different results. The Industry Trades recommend that EPA clarifies how thermal energy measurements should be converted to mmBTU, and the Industry Trades also recommend adding a reporting field for both cold and hot energy products in the reporting form.

e. As proposed, Subpart B provisions for thermal energy reporting only address the purchased energy, which may not represent the energy consumed on-site. The Industry Trades propose reporting this information on a facility-wide net-energy basis. Many facilities that purchase steam also return condensate, which has embodied energy that is not consumed at the purchaser's facility. Also, some facilities that utilize electrical and/or thermal energy from a provider may pass through some of the energy purchased to a third party. In order for EPA to understand the energy consumed at the facility, both thermal energy purchased and condensate returned or energy passed through need to be understood. The Industry Trades believe that reporting this information on a net-energy use basis will provide clearer information regarding thermal energy usage.

f. The Industry Trades also request EPA to remove, or at least provide clarification/guidance regarding, the requirement to assign the decimal fraction of purchased energy to applicable GHGRP Subparts under 98.26(l) for larger integrated facilities that utilize multiple external electrical/thermal connections with on-site energy generating units or thermal production units, as it would be overly burdensome to reasonably segregate and calculate purchased energy from site generated energy with any reasonable confidence due to the fluid nature of imported and exported energy across a large facility. Similarly, guidance of scenarios on calculating excluded quantities under 98.26(j)(4) would be valuable for the regulated community as purchasing/selling of energy may overlap based on energy loading across the larger integrated facilities and surrounding community.

g. The definition of thermal energy that states "or any other medium used to transfer thermal energy and delivered to a facility" is overly broad and ambiguous. For example, it is unclear if purchased raw water utilized as cooling tower make-up water would be subject to the requirements, even though there may be no associated indirect emissions. The Industry Trades request clarification of the definition of thermal energy to only include thermal products where the primary reason for purchase is energy transfer and where energy was required to achieve a specific thermal property for the purchased products prior to metering. Similarly, the Industry Trades recommend incorporation of a reference temperature (e.g., outside of ambient) to define thermal energy products to avoid confusion.

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h. Likewise, EPA's proposed definition of thermal energy also includes refrigerants. Clarification should be made that this excludes non-industrial process uses such as refrigerants for comfort cooling and food storage. In most cases these are not "metered," but this exclusion would avoid confusion. The Industry Trades respectfully recommend adding the proposed language ***in red*** below:

   "Thermal energy products means metered steam, hot water, hot oil, chilled water, refrigerant, or any other medium used to transfer thermal energy and delivered to a facility subject to this subpart. ***Thermal energy products do not include those used for non-industrial purposes such as comfort heating/cooling and food storage/preparation."***

Additional Comments Sought by EPA:

EPA is seeking comment on existing industry standards for assessing the accuracy of electric and thermal energy monitoring systems, the frequency of audits of these systems, and the accuracy specification(s) used for thermal energy product metering systems. Consistent with the Industry Trades' position on the meter-level QA/QC and accuracy requirements, the Industry Trades' members are not generally energy providers and cannot comment on the accuracy of electrical and thermal energy monitoring systems. However, it is the Industry Trades' position that any audits of these electric and thermal energy monitoring systems be performed only during a planned facility shut-down.

EPA is also seeking comment on their understanding that monitoring and recordkeeping systems are already in place for purchased energy transactions and on EPA's assessment that the incremental reporting burden would be minimal. As reflected in the comments in this section, the Industry Trades believe that the recordkeeping and QA/QC requirements as proposed would be extremely burdensome for operations across large geographic areas, such as oil and natural gas operations.

2. Subpart WW – Coke Calciners

The proposed Subpart WW includes two proposed calculation methods to determine the CO_2 emissions from coke calciners in section 40 CFR §98.493(a). The first method uses the Tier 4 method that requires Continuous Emissions Monitoring Systems (CEMS) and requires a stack flowmeter. Stack flowmeters on coke calciners can be unreliable and can be difficult to maintain while the unit is operating. Coke calcining units that do not currently have a stack flowmeter would need to purchase, install, maintain and calibrate them, which could be a cost in excess of the Capital and O&M costs given in Table 10 for an incremental burden.

The second method is a carbon balance based on the mass and composition of the green carbon feed, petroleum coke dust and marketable coke produced. Coke calcining units that do not currently weigh all of these streams or conduct regular sampling could be required to install new scales and collect and analyze samples which may again require expenditures in excess of the incremental burden costs estimated in Table 10. There may be issues getting the carbon mass to balance, as uncertainties in weights and coke composition could lead to under or overestimation of CO_2 emissions.

There is a third method, currently used at a coke calcining unit and currently used to comply with a Washington State GHG Reporting program, that should be included as an approved method in Subpart WW section §98.493(a). In this method a performance test is conducted to measure the stack flow while the CO_2 and O_2 concentrations are measured using a CEMs system, and either the green coke input or calcined coke output is weighed. The result of the performance test is to determine the coke calciner stack flow based on either green carbon input or marketable coke output. This allows the CO_2 emissions for each hour of the year to be calculated using the weighed coke input or output, the CEMs CO_2 and O_2 concentrations and the stack flow factor from the performance test. The performance test is conducted periodically and the factor from the last test is used until the next stack test is performed. The stack flow factor is corrected to a set excess oxygen concentration, and the CEMs data measured throughout the year to allow the measured CO_2 concentration to be corrected to the same excess oxygen concentration.

This third method combines elements from both of the methods currently included in the proposed Subpart WW. It has an advantage that use of a stack flow factor prevents potential large periods of data substitution when the stack flowmeter is not operating. The Industry Trades request that EPA add this third method to the proposed Subpart WW. The addition of an alternate State approved method is consistent with provisions that the EPA has previously made in the Tier 4 methodology in 40 CFR 98.34(c)(1)(iii) and 40 CFR 98.36(e)(2)(vii)(A) that allow a State approved monitoring program.

Summary

The undersigned associations, representing the oil and natural gas industry, appreciate EPA's willingness to collaboratively engage with the regulated community in order to improve the quality and consistency of reported data while also streamlining the reporting process. The comments provided in this letter are intended to support this effort by providing EPA with additional context and potential unintended consequences associated with some of the proposed reporting, recordkeeping, and QA/QC requirements.

The Industry Trades are working to reduce GHG emissions across the value chain of the oil and natural gas industry, and it is critical that the EPA and the GHGRP reflect accurate reporting of GHG emissions. To that extent, it is important that EPA carefully consider these proposed revisions and new subparts and consider the points outlined by the Industry Trades while considering future proposed rulemaking.

The undersigned associations encourage EPA to carefully consider the comments and recommendations contained within this letter, and we stand ready to respond to questions and provide further clarifications, as needed, from EPA. For more information, please contact Jose Godoy at Godoyj@api.org or 202-682-8073.

Sincerely

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Offshore Operators Committee

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Mark DeFigueiredo, Office of Atmospheric Programs, EPA

Docket ID No. EPA-HQ-OAR-2023-0234
October 2, 2023

ANNEX C: API Comments on EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023

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Submitted via regulations.gov

February 13, 2023

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W. Washington, D.C. 20460

Attention: Docket ID EPA-HQ-OAR-2021-0317

RE: Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Including Appendix K and Social Cost of Greenhouse Gases

Dear Administrator Regan:

The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (87 FR 74702, December 6, 2022) ("Supplemental Proposal"). This submittal includes comments on the associated Appendix K proposal and EPA's "Report on the Social Cost of Greenhouse Gases".

API is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. Gross Domestic Product (GDP). API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators, and marine transporters, as well as service and supply companies, providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

As we indicated in our comments on EPA's November 2021 Proposal (86 FR 63110, November 15, 2021), API supports the cost-effective, technically feasible, direct federal regulation of methane from new and existing sources across the supply chain. We appreciate EPA's further development of a fugitive emissions monitoring framework that allows for use of advanced detection technologies. We also appreciate EPA's recognition that Appendix K's monitoring protocol is not appropriate for the upstream production and transmission segments. While we appreciate EPA's responsiveness to many of the issues raised in our comments[1] on the November 2021 Proposal, nevertheless, we have serious concerns regarding the cost effectiveness, technical feasibility, and legal soundness of many aspects of the Supplemental Proposal. We also have extensive concerns with EPA's Draft Report on the Social Cost of Greenhouse Gases and the lack of transparency in the Interagency Working Group's process. Moreover, we strongly disagree with EPA's assertion[2] that November 15, 2021 can serve as the applicability date of the final rule for new, reconstructed, and modified sources.

Reducing methane emissions is a shared priority for EPA and our industry. We are committed to advancing the development, testing, and utilization of new technologies and practices to better understand, detect, and further mitigate emissions. In recent years, energy producers have implemented leak detection and repair (LDAR) programs, phased out the use of high-bleed pneumatic controllers, and reduced emissions associated with flaring – voluntarily and under federal and state regulations. Voluntary, industry-led initiatives such as The Environmental Partnership[3] have built on the progress industry has made to reduce emissions and continuously improve environmental performance. Since its founding in 2017, the Partnership has grown to include over 100 companies representing over 70% of total U.S. onshore oil and natural gas production.

The New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc are complex rules that will apply to hundreds of thousands of facilities owned and operated by these and other companies, including many facilities that have not previously been subject to regulation under the Clean Air Act. Because of the wide variety of conditions faced by these facilities, the novel nature of a first ever existing source rule, and timing of the Supplemental Proposal's release and subsequent overlap with the holiday season, API requested[4] an extension of the comment period to allow additional time for our staff and our members to fully review the Supplemental Proposal and provide EPA with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. As we noted, API members who are engaged on this issue have been concurrently engaged in reviewing additional recent legal and regulatory developments on this subject matter. We regret that EPA did not grant the request and may rush to completion of a final rule that does not reflect the full measure of consideration necessary to ensure cost effectiveness, technical feasibility, and legal soundness.

In our review of the Supplemental Proposal, API once again considered the effectiveness of emission reduction strategies, safety, feasibility, operability, and cost. Where appropriate, we have recommended changes to the regulatory text that will enable the final rule to meet these critically

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[1] EPA-HQ-OAR-2021-0317-0808
[2] 87 FR 74716
[3] http://www.theenvironmentalpartnership.com
[4] EPA-HQ-OAR-2021-0317-1588

important criteria. We have also detailed the necessity of workable implementation timelines that consider the supply chain and labor constraints facing our industry, constraints which will be exacerbated as the final rule takes effect. The adoption of the recommendations in our comments in the final rule would reflect a more cost-effective and technically feasible regulation of methane.

API appreciates EPA’s engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize a cost-effective rule that incentivizes innovation, advances the progress made in reducing emissions and addressing climate change, and ensures that our industry can continue to provide the world with the affordable, reliable energy it requires.

If you have any questions regarding the content of these comments, please contact Ryan Steadley at steadleyr@api.org.

Sincerely,

cc:

Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Karen Marsh, EPA
Steve Fruh, EPA
Amy Hambrick, EPA

API Comments on EPA’s Proposed “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review”

(Proposed NSPS OOOOb, EG OOOOc, Appendix K and the Social Cost of Greenhouse Gases)

Docket ID: EPA-HQ-OAR-2021-0317

February 13, 2023

Executive Summary

The American Petroleum Institute (API) supports certain aspects of the Supplemental Proposal for New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc and remains committed to working with the Environmental Protection Agency (EPA) and the Administration to identify cost-effective emission control opportunities. The comments provided herein focus on legal, technical, and feasibility challenges with specific provisions that EPA included within the Supplemental Proposal of NSPS OOOOb and EG OOOOc. Listed below are API's primary concerns with the proposed rules.

To facilitate review of our comments, API has summarized these concerns and provided reference to the detailed comments where additional supporting discussion has been included. Our members look forward to continued dialogue and engagement as EPA works towards finalizing these important rules.

1) **The Applicability Date for NSPS OOOOb should be December 6, 2022.**
The Clean Air Act (CAA) Section (§) 111(a)(2) definition of "new source" uses the term "proposed regulations" in defining the new source trigger date. The November 2021 preamble alone cannot constitute a proposed rule any more than a final rule that is unaccompanied by regulatory text could be declared a "rule." Although the November 2021 preamble described the type of regulatory requirements that EPA contemplated promulgating, the preamble was not in and of itself a document that establishes the "agency statement of general or particular applicability and future effect." That type of required statement would be established only by the proposed regulatory text, which was not provided until the December 2022 Supplemental Proposal. Many of the requirements included in the proposed regulatory text could not have been gleaned from the prior descriptions provided. Refer to Comment 8.1 and Comment 12.1.

2) **Adequate implementation time must be provided for NSPS OOOOb and EG OOOOc.**
NSPS OOOOb and EG OOOOc will apply to hundreds of thousands of sites when implemented. Our members are already experiencing a noticeable delay in the supply chain for equipment required by the proposed rules including (but not limited to) control devices, flow monitoring equipment, instrument air systems, solar panels, etc. Control devices are currently experiencing delays of 3 to4 months, while flow monitors are on backorder for a minimum of 6 to8 months from suppliers. Instrument air systems (including the air compressor and associated equipment) are nearly 1 year on backorder, and recently ordered solar panels are delayed between 18 to24 months. As more facilities become subject to proposed requirements in NSPS OOOOb and EG OOOOc, the above timelines are anticipated to be exacerbated before the market experiences a correction to meet these new levels of demand. We provide more detail related to current supply chain delays in Comment 5.2 and Comment 7.1. We request EPA consider these challenges prior to finalization of certain provisions within these rules to allow operators the ability to acquire and install the required equipment. Additionally, EPA should allow more time for new, modified, and reconstructed sources to come into compliance with NSPS OOOOb if it maintains the current applicability date of November 15, 2021.

3) **Associated gas provisions need to be significantly modified.**
Whereas API supports and recognizes the environmental benefit of eliminating the venting of associated gas from oil wells, EPA must recognize the distinction between associated gas from oil wells that route to a sales line and oil wells that do not have adequate or accessible gas gathering infrastructure. Removing wells connected to sales lines (or recovering gas for another primary purpose) from the requirements of the associated gas provisions would help to eliminate confusion resulting from EPA introducing its own interpretation of "flaring" when multiple definitions of "routine flaring" already exist in state and voluntary programs. Additionally, API does not support the requirement to make an infeasibility demonstration, along with safety and technical certifications in order to flare associated gas. Refer to Comment 4.0. and Comment 12.9.

4) **As proposed, the Super-Emitter Response Program presents numerous legal, logistical, commercial, safety, and security risks that have not been adequately considered by EPA within the Supplemental Proposal.**
To address these concerns (and assuming EPA resolves the legal deficiencies), numerous adjustments to the proposed framework are necessary. Specifically, EPA must establish requirements for monitoring of third-party data, provide a formal notification process that includes EPA involvement and review, and provide limitations on how any monitored data is released and used publicly. Refer to Comment 1.0, Comment 12.3, and Comment 12.4.

5) **In determining storage vessels affected facility Potential to Emit, EPA's proposed criteria for legally and practicably enforceable limits have broad legal implications and pose several permitting challenges.**
The proposed criteria and the additional methane emissions threshold may be lacking in existing permits that have previously been understood to be legally and practicably enforceable and may also be impossible to obtain under existing permitting mechanisms. EPA should continue to defer to the states on sufficient monitoring, recordkeeping, and reporting requirements to include in permits to establish legally and practicably enforceable limits. API also offers suggestions concerning various definitions and proposed control requirements for storage vessels affected facilities. Refer to Comment 6.0. and Comment 12.10.

6) **As proposed, alternative technology requirements for fugitive emissions monitoring, including continuous monitoring, are impractical and may disincentivize the use of this emerging technology.**
API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA to make key adjustments in the final rule to enhance the use, and not unintentionally disincentivize development and deployment of these technologies. In particular, we believe there should be approved technologies for operators' use at the time the rule is finalized, alternate technologies should not be held to a greater level of stringency (i.e., frequency) than Best System of Emission Reduction (BSER) as currently proposed, and EPA should streamline the timeline and actions to conduct repairs. Refer to Comment 3.0.

7) **API proposes AVO inspections only at multi-wellhead only sites.**
EPA's focus on finding large fugitive emissions at single wellhead only sites using audio, visual, olfactory (AVO) inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall

well site emissions. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Refer to Comment 2.1.

8) **EPA should clarify its preamble language concerning leaks detected from a cover or a closed vent system during associated inspections or other fugitive emissions monitoring.** Emissions detected from covers and closed vent systems do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented. Like standards for other fugitive emissions components, the "no identifiable emissions" standard is a work practice standard rather than a numerical emissions standard. Therefore, EPA must make it clear that a cover or closed vent system remains in compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed. Regarding control devices, API recommends a compliance extension of at least one year for the proposed monitoring requirements. We also offer suggestions to provide consistency between manufacturer-tested devices and other enclosed combustion devices as well as request EPA provide the necessary monitoring alternatives given the increased number of control devices subject to proposed monitoring requirements. Refer to Comment 5.0.

9) **EPA should amend many of the provisions within the Supplemental Proposal to work practice standards and eliminate the additional technical demonstrations with accompanying certification statements.** EPA has added several certification statements throughout the proposed requirements for NSPS OOOOb and EG OOOOc – including certifications for pneumatic pumps, gas well liquids unloading operations, and associated gas from oil wells. EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating exceptions that require technical demonstrations and engineering certification. Inclusion of these technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA § 111 because non-emitting standards are not "adequately demonstrated" if exceptions are needed to make them feasible and workable. Regarding the certification statements themselves, a certified official is already required to sign the report certifying the company's compliance with all applicable provisions. These additional certifications should be removed prior to finalization of these standards for associated gas from oil wells, pneumatic pumps, and gas well liquids unloading operations. Refer to Comment 4.1, Comment 8.2, Comment 9.1, Comment 10.1, and Comment 12.9

10) **Requirements for pneumatic controllers and pneumatics pumps should be simplified and aligned.** While we support EPA's proposal for defining the affected facility for both pneumatic controllers and pumps as the collective, we have numerous concerns with the practical and logistical aspects of how EPA has outlined control standards between the two sources. Specifically, EPA has proposed a completely distinct set of requirements for natural gas-driven controllers separate from natural gas-driven pneumatic pumps with sometimes conflicting statements made to justify EPA's decisions. The requirements for both pneumatic controllers and pumps should be streamlined for consistency with neutral technology standards that do not require additional certifications and allow for emissions to be routed to a control device. Refer to Comment 7.0 and Comment 8.0.

11) **EPA should streamline the recordkeeping and reporting requirements associated with compliance assurance of the proposed rules.**
    EPA should continue to streamline both recordkeeping and reporting as it relates to these proposed requirements to include only the necessary information that will help assure compliance. Streamlining is especially critical for locations with existing sources as the cumulative impacts for tracking records are anticipated to be much larger than EPA estimates and will apply to hundreds of thousands of sites across the U.S. For some sources, EPA has described requiring records and potential reporting of information that does not link directly to emission controls or work practices, which API does not support. We support inclusion of recordkeeping and reporting that help demonstrate compliance with less administrative burden. Refer to Comment 9.3 and Comment 13.2.

12) **EPA should grant equivalency for state programs across emission sources for NSPS OOOOb and EG OOOOc.**
    Given EPA has described many requirements that are consistent with those at the state level (e.g., Colorado, New Mexico, and California), EPA should allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb and EG OOOOc where it is appropriate to do so for leak detection and repair (fugitive emission monitoring) and other emission control provisions. EPA should allow states the opportunity to demonstrate programmatic equivalency, including addressing deviations from the form of the proposed standards. Without this, states and operators may be administering and complying with two sets of requirements (standards and administrative) that are duplicative because they are intended to achieve similar goals but are not perfectly identical. It also precludes innovative regulatory approaches from states. Refer to Comment 12.6 and Comment 12.7.

13) **EPA should carefully consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc in conjunction with the cumulative burden imposed through provisons in the Supplemental Proposal.**
    EPA must consider the cumulative burden imposed to the regulated community of numerous and onerous provisions in the Supplemental Proposal, especially due to the unprecedented number of sources that will be subject to the rule given the proposed November 2021 applicability date for new, modified, and reconstructed sources. EPA must also consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc and the difficulty the industry has faced to fully understand the impacts of this rule without a comment extension. These difficulties for the regulated community have been compounded by other rules that impact the same sources (e.g., Bureau of Land Management's (BLM's) Waste Prevention Proposal). Specifically, EPA needs to be clear on the disposition of NSPS OOOO and OOOOa applicable sources if and when they become subject to EG OOOOc. Finally, EPA must revise its Regulatory Impact Analysis, including the potential for lost production stemming from implementation of these rules. Refer to Comment 12.1 and Comment 12.5.

14) **For equipment leaks at onshore natural gas processing plants, API recommends that closed vent systems be monitored annually and that appropriate VOC and methane concentration thresholds be established for applicability.**
    While API supports the proposed bimonthly OGI monitoring as well as the proposed alternative monitoring based on the incorporated NSPS VVa requirements with simplifications, we have concerns with the proposed frequency for closed vent systems and the proposed potential to emit applicability threshold for VOC. While we generally support the proposed Appendix K for OGI monitoring at gas plants, we have several comments regarding proposed Appendix K as provided in Attachment A. Other

comments on leak detection and repair at gas plants include our recommendation on the proposed definition of equipment for capital expenditure evaluations. Refer to Comment 11.0 and Attachment A.

15) **API appreciates EPA's decision to accept comments specifically on the EPA's Social Cost of Greenhouse Gas (SC-GHG) Report, but we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates.**
API shares the Administration's goal of reducing economy- wide GHG emissions. With respect to SC-GHG our concerns stem from the approach taken by EPA, including the anticipated role of these new estimates in EPA's rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group. Refer to Comment 13.5 and Attachment B.

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Attachment B – Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

PROPOSED NSPS AND EMISSIONS GUIDELINES FOR THE OIL AND NATURAL GAS SECTOR (NSPS OOOOb AND EG OOOOc) INCLUDING APPENDIX K

DOCKET ID: EPA-HQ-OAR-2021-0317

While we have made every effort to thoroughly review both proposed New Source Performance Standard (NSPS) OOOOb and Emission Guidelines (EG) OOOOc as we formulated these comments, there may be places where we only provide a citation or reference as it pertains to proposed regulatory text in NSPS OOOOb. Unless we have provided a distinctly separate comment as the topic pertains to EG OOOOc, we also intend the comment to apply to proposed EG OOOOc. Additionally, when using the terms "proposal" or "standards" in these comments in reference to the November 2021 preamble, it does not constitute a "proposed rule" or "emission standard" for purposes of triggering applicability under CAA § 111(a)(2).

1.0 Super Emitter Response Program

As proposed, the Super Emitter Response Program (SERP) presents numerous legal[5], logistical, commercial, safety, and security risks that have not been adequately considered by the EPA and are the basis for the comments we offer herein. These complex issues would benefit from further discussions between EPA, operators, and other interested parties.

Our members understand the importance of identifying and addressing large emissions events and any future support for a program would be grounded in a shared interest to reduce the incidence of these emission events. For over three decades, EPA and industry have successfully collaborated on the implementation of voluntary programs to reduce methane emissions from the oil and natural gas sector under both the Natural Gas Star and Methane Challenge Programs. While we believe the SERP may be better suited to function as a voluntary based program, API members recognize the intent of the EPA to create a useable and workable program that identifies these large emissions events from a variety of stakeholders.

We encourage EPA to conduct additional outreach on the proposed framework and repropose a program that meets all Clean Air Act legal requirements prior to finalizing the requirements (as provided in §60.5371b). Our members would welcome the opportunity for future discussions on this important topic.

1.1 API proposes a programmatic framework that is managed by EPA and incentivizes the finding and subsequent repair of potential super emitter emission events.

EPA has described the SERP as a backstop to the requirements of NSPS OOOOb and EG OOOOc. However, as we describe throughout our comments there are serious legal, logistical, commercial, safety, and security problems inherent in EPA's proposed program. The framework we have described herein achieves the goals EPA has described for the program while addressing the concerns API members have with EPA's proposal.

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[5] See Comment 12.3 and 12.4 of this letter for a discussion of the numerous legal deficiencies underpinning the proposed SERP.

For the SERP to be effective, EPA must reconsider the operational flow of how the program will function and be implemented. This framework includes adding formal notifications first from third parties to EPA and then from EPA to operators. We also specifically offer suggestions on clear timelines for all participants of the program where information can be transferred in a clear and transparent order, which we have emphasized in our framework.

Below we have outlined our suggestions on the appropriate steps to be included in a reproposed framework, which provides greater confidence that the data provided under the program will be valid, actionable, and achieve EPA's goals for transparency within the program.

1) The third party completes approval certification process by EPA for inclusion in the Super-Emitter Response Program and becomes "certified or re-certified".
2) Certified third party[6] notifies EPA of planned monitoring, including submittal of a monitoring plan, at least **30 business days** prior to planned monitoring. Depending on technology deployed, such as satellites, this pre-approval may include flight plans for extended time periods. The components of the monitoring plan are more fully described in Comment 1.1.3 of this letter.
3) EPA reviews the certified third parties' monitoring plan for approval or disapproval.
    a. If approved, EPA notifies the impacted operators at least **7 business days prior** to monitoring with details of the monitoring to be conducted including technology planned for use, dates of monitoring, flight paths (if appropriate), etc. This notice essentially acts as a "pre-notification" to operators, which enables the operator to have staff available to ensure safety of operations, if warranted based on technology that will be used to detect potential emissions by a third-party.
    b. This "pre-notification" may also help both EPA and the third-party identify the appropriate operators, including the correct contact information, in the event a super emitting emissions event is detected. The potential for incorrect identification of operators is of concern for our members.
4) Timing of notification of results of monitoring to the operator is critical to the effectiveness of the SERP. After monitoring is completed, third party has **2 calendar days** to provide data as defined in §60.5371b(b) to the EPA.
5) If EPA determines the data provided by the third-party to be credible and warrants investigation, EPA provides data for any super emitter emission event to the appropriate operator(s) within **3 calendar days** of verification of third-party monitored data.[7]
6) Operator(s) will initiate an investigative analysis **within 5 business days** of receipt of data from EPA and complete the investigation within **10 business days** of receipt of the data from EPA.
    a. Given how certain technology is applied, the detection may not be from the facility that was notified, may be a permitted release, may be due to maintenance activity, or another reason that does not require action (such as monitoring data calibration issue). If the emissions event was the result of a permitted activity or could not be validated after full investigation by the operator, the

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[6] For the purpose of these comments when we reference a 'third-party', "certified notifier" or 'certified third-party' we mean the certified individual and the monitoring company whose technology is utilized to conduct monitoring.

[7] The basis for the timing proposed in steps 4 and 5 is to align with what EPA has proposed for operators using similar technology.

operator will provide "no action required" demonstration to EPA as specified in §60.5371b(c)(8) and §60.5371b(e)(1).

   b. If the emissions event was result of component failure or other equipment defect, the operator(s) will complete final repairs **<u>within 15 calendar days</u>** after completing the investigative analysis.

7) All public information should be published by EPA only. EPA should manage all data that is to be public and establish a protocol for when and what type of specific details of a potential super-emitter emissions event is published via EPA's proposed website per §60.5371b(e)(4). We strongly disagree with the assertion in Section IV.C.2.a of the preamble (87 FR 74750) which states "*The EPA would then promptly make such reports available to the public online. Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting.*" Given that much of the data collected can be interpreted incorrectly and not aligned with operating conditions, the EPA should be the only authority to publish data, and EPA should publish data only after operators have had an opportunity to review and respond to the information and EPA has fully reviewed and vetted follow-up actions with the operator.

The timing of each step in the above framework has been crafted with the intent that all participants are held to timelines that are workable and suitable for each step of the framework. Operators are concerned they could receive multiple third-party notifications with limited time and resources to respond appropriately if stricter timing criteria for third parties to provide data is not established. The above framework seeks to address this concern.

1.1.1 EPA should establish transparent certification requirements for third-party monitoring.

Two-way accountability will allow for efficient and effective execution of the super-emitter response program. EPA should develop a clear set of criteria (e.g., in a checklist form) that any certified third-party would need to meet to participate in the program. This certification is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. We appreciate the demonstration for third-party notifiers as outlined in the preamble (87 FR 74750), but do not believe the requirements as proposed in §60.5371b(a) provide enough stringency. Considering the requirements EPA has established for an operator, the same level of scrutiny should also be expected of the third-party data provider when using the same technology. Strict criteria should be established covering the following:

- An expectation from EPA that third parties and their approved detection technologies must be re-certified on a specified frequency. This certification process should be similar to other EPA certifying programs (e.g., EPA auditor).

- An expectation for third parties to attend EPA-specific training, including the do's/don'ts as well as what they are authorized to do or not do – including the handling of data they plan to use within the program.

- Clear criteria for what type of actions may immediately make data collected invalid and/or fully revoke a third party's participation in the program. Regarding EPA's proposed revocation of third party certification (87 FR 74750), we recommend that the criteria for revocation explicitly state that upon a third party's third submission of verifiably false data from any combination of operators or sites, or upon trespass or otherwise unlawful or unauthorized entry to a facility, or vandalizing energy infrastructure, or upon unauthorized distribution or publication of data gathered under the program, the offending third party

shall have their certification revoked for a period of no less than three years. Any data gathered at the time of a trespass would render that data invalid.

1.1.2 The super emitter response program must have a transparent and formal notification process where EPA manages the flow of information from the third-party to the operator.

As similarly done with other EPA programs, formal notification to facility owners/operators (and even with the third-party) could potentially be via email or a central online-based system.[8] The process should allow EPA to confirm that the correct operator received the notification and follow-up if the operator does not respond within a certain timeframe. There are also concerns with measurement of emission events, including pin-pointing sources or facilities correctly (especially when there are adjacent facilities in proximity to each other or sharing boundaries), and in conjunction with the minimum resolution of the monitoring technologies.

Some additional considerations include the following:

- **Operators should be given advanced notice of planned third-party activity. As proposed, the response burden for operators is not predictable and operators are unable to properly plan and schedule resources.** If timing and location of surveys are unknown to a facility owner/operator, operators will have no indication of when and how much resources to have available. This is important to promptly evaluate data and implement corrective action if necessary. Third parties may employ technologies, like aerial surveys which can result in multiple detections in a short amount of time. It's not unreasonable to expect that surveys may be conducted by multiple third parties simultaneously or in series, and conversely, there could be extended periods of no third-party activity. Program requirements must balance the needs of operators to plan for both day-to-day operations and promptly prepare for and respond to third-party activity.

- **Detections of potential super-emitter emission events should be shared with the operator within a certain time period from detection to allow for effective and prompt response to reduce the emission impact.** As proposed, third parties only have to provide data *"as soon as practicable to the owner or operator"* under §60.5371b(b)(7). Since there could be many days between when monitoring occurred and when an operator receives the survey data, an investigative analysis may not find any significant ongoing / persistent emissions event. Furthermore, third-party notifiers could attempt to overwhelm a single operator with a rush of data from multiple monitoring campaigns (e.g., using remote-sensing equipment on aircraft) that would be untenable to fully investigate.

We propose suggested timing for these notifications in Comment 1.1.

1.1.3 Monitoring conducted by a third-party should be pre-approved and accepted by EPA prior to execution of the data gathering event.

There are clear protocols, including monitoring plans, that operators are required to have in place to conduct emission monitoring data. Any certified third party that conducts monitoring must be held to the same stringency

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[8] If an online-based system is chosen, there will be an additional resource / cost burden on EPA to develop and maintain the functionality of the system. Also, there may be an issue when operators are in close proximity to each other and have shared property boundaries, or when a facility was owned by a specific operator at one time but has been sold to another owner.

as an operator if they were to use the same technology. This reciprocity is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. It also is necessary, given that third-party monitoring would create enforceable legal obligations for affected/designated facilities as currently proposed. There is nothing under the law that, in and of itself, prevents any third party from conducting remote monitoring (as noted elsewhere, the law may impose restrictions on where/when/how such monitoring may be done; for example, third-party monitors may not trespass on private property). But when such monitoring has regulatory consequences, it would be arbitrary and fundamentally inconsistent for EPA to set more lenient criteria on third-party monitors than it does for similar monitoring required to be conducted by affected/designated facilities.

At least 30 business days in advance of the planned monitoring campaign, the third-party must submit a monitoring plan to the EPA for approval. The monitoring plan submittal should include the following information (at a minimum):

- Site coordinates and/or map of the area to be monitored;
- Description of monitoring equipment to be used to conduct the activity;
- Documentation of emissions detection limit;
- Proposed starting date and duration of the monitoring activity;
- Contact details (e.g., name, phone number, title) of third-party contact person;
- Name and details of owner of remote monitoring equipment;
- Quality assurance / quality control plan, including calibration procedures, if applicable to the technology (Subsequently, the third-party should also have to demonstrate how it met its monitoring plan for each monitoring event when monitored data is submitted to EPA);
- Specification on how the data will be provided and in what timeframe to the EPA; and
- Certification statement signed by an authorized company official attesting that the third-party will conduct monitoring activities in accordance with EPA requirements.

With the 30-day approval period, it would also allow EPA sufficient time to provide affected facility owners / operators notice of the upcoming monitoring event, which should be provided at a minimum 7 business days prior to the start of the monitoring field event.

1.1.4 There are safety and security concerns with third parties trespassing on private property.

Even though EPA notes in Section IV.C.2.a of the preamble (87 FR 74749) that it considered concerns for the safety of individuals engaged in third-party monitoring and of facility operator personnel, there are still tangible safety concerns related to the use of certain monitoring technology by third parties (e.g., mobile monitoring platforms) to identify super-emitter emissions events. Some operators have experienced public individuals driving through operator sites (especially in remote locations with no “fencing”) with vehicle mounted monitoring devices, which is especially problematic as access can typically be obtained by road, some of which may be private

roads. There have also been issues acknowledged between private third-party landowners and trespassers, which can be another point of contention.

Personnel working at our facilities are required to undergo numerous hours of training to safely perform their work duties, including but not limited to wearing the correct personal protective equipment based on site conditions, exposure to extreme heat or cold weather, biologic hazards such as snakes or other critters, specific training on how to navigate rotating equipment, and where and how to identify hazardous chemicals/gas. For example, training specific to the presence of hydrogen sulfide (H_2S) includes hazards, symptoms of exposure, detection devices, and how to safely walk away from exposure.

Individuals require site specific training to be present at any given facility and there is potential liability (to both the individuals and to company assets) for individuals who do not have this training. The proposed SERP framework is geared to remote technologies, which by their nature should in no way necessitate third-party representatives to appear at facilities. API recommends that any information that is collected by a third party that is outside of an EPA-approved monitoring campaign, where EPA and/or operators have not been notified in advance of the data gathering campaign, be considered invalid. As we also provided in Comment 1.1.1 , trespassing (such as driving through a site) should immediately result in revocation of a third party's certification and render any information gathered at the time invalid.

1.1.5 The EPA should clearly manage how third-party monitored data is published in conjunction with corrective actions taken by operators.

Participation in the regulatory process through the super-emitter response program by EPA-certified third parties must include limitations on the ability of those third parties to use the information gathered under the program for any other purpose. Such limitations must include requirements that the third party (and the monitoring companies they contract) maintain the security and confidentiality of data collected during SERP monitoring, where the monitoring results cannot be independently published (via website or social media). EPA has a fundamental role to play in the validation of third party collected data, which extends to the publication of such data. When a third party accepts the responsibility of participating as a certified notifier, they accept this role and handling of data.

- **Monitored data should not be published without context from operator feedback or corrective actions.** EPA's state within the preamble (87 FR 74750) "*owners and operators would have the opportunity to rebut any information in a notification provided by the qualified third parties in their written report to the EPA, by explaining, where appropriate, that (a) there was a demonstrable error in the third party notification; (b) the emissions event did not occur at a regulated facility; or (c) the emissions event was not the result of malfunctions or abnormal operation that could be mitigated.*" While we agree with this concept*,* the proposed framework does not provide the same level of assurance that these rebuttal statements would be linked to the third-party monitored data directly in the public forum without EPA intervention. If the data is posted on other public websites, there is a chance any resolution/follow up comments and descriptions from operators will not be carried over to the non-EPA sites, therefore resulting in inaccurate presentation of the facts. While we concur that data transparency is valuable, and share the goal of disseminating information to mitigate emissions events, these goals must be balanced with adequate considerations for national security risks, reputational risks (e.g., incorrect operator maligned in media, third party is not approved or certified by EPA, permitted events are taken out of context, etc.), and stakeholder risks.

- **EPA should establish a protocol or annual publication updating on progress of the program.** We believe the current language proposed in §60.5371b(e)(4) establishing a new EPA website is extremely flawed and ambiguous. Third-party monitored data on its own will provide very limited context for the general public and can be easily taken out of context. We believe a synthesized annual report or fact sheet published by EPA would offer a clearer depiction of relevant details with full context around super emitters including but not limited to: how many third-party monitoring events took place, the number and location of valid super emitter emission events that were detected, the number of super emitter events that were permitted or authorized emissions, the rate of erroneous notifications and the types of corrective actions that were taken to repair other super emitter emissions identified. Operator related information could remain anonymous in this annual report, unless EPA found specific operators to be conducting insufficient corrective actions or operators that do not acknowledge EPA's notification attempts regarding the monitoring campaigns (and EPA has verified the correct operator and contact information).

  At a minimum, EPA should limit the information for super-emitter emissions events so that the information cannot be misconstrued or used to publicly attack operators in the media; especially operators who are proactive participants within the SERP. The shared goal of finding these leaks and fixing them as expeditiously as possible should remain at the forefront and in conjunction with transparency objectives.

1.1.6 An "investigative" analysis should be conducted in conjunction with initial corrective actions.

As we explain further in Comment 3.2, the EPA outlines in §60.5371b(c) specific actions to take place if a super-emitter emission event occurs. API supports investigating the source and cause(s) of significant emissions events that are brought to an operator's attention Through the process described in our comments. We agree that EPA's investigative actions listed §60.5371b(c) are appropriate and practicable as far as investigating and conducting initial corrective actions for super emitter events. However, EPA's use of the term "root cause analysis" is problematic and ambiguous. The concept of "root cause analysis" is embedded in numerous other regulatory and non-regulatory programs and has varied meaning and purpose in each application. Thus, use of that term here does not clearly and adequately define the scope of the legal obligation, which will make it difficult for operators to understand what must be done to comply and will invite dispute and controversy if/when this program is implemented. To address this concern, we recommend the actions EPA has outlined be maintained, but the term supplied as the definition for those actions be changed to "investigative analysis" as it relates to super-emitters in §60.5371b(c).

1.1.7 After an investigative analysis has occurred, an operator should have the ability to designate the emission event as "no action required," as applicable.

Since the source of an emission detection during a monitoring campaign could be the result of various situations (and even EPA acknowledges that there may be demonstrable errored data), API suggests that the EPA include a pathway for operators to simply identify situations where "no corrective action required" beyond what has been proposed in §60.5371b(e)(1). These additional situations could include 1) the wrong operator was notified; 2) where the emission event cannot be validated by the operator; 3) there was a demonstrable error in the third-party notification; (4) the emission event did not occur at a regulated facility (e.g., well site or compressor station); or 5) the emission event was authorized as authorized or permitted operations. The information an operator should submit back to EPA should be simplified for planned or authorized emissions. Further, within

§60.5371b(e)(1)(iii), EPA must clarify that the applicable standard is limited to the applicable standard of this subpart.

1.1.8 Safe Harbor for Operators

The presence of a super emitter emission event does not necessarily indicate a standard has been exceeded or that a violation has occurred. Moreover, any documents shared with EPA articulating corrective actions taken should be subject to a safe harbor provision that prevents EPA or any other entity from using the information in the document for purposes of enforcement / notice of violation (NOV), civil suit, etc.

1.1.9 The role of states as a delegated authority within the super emitter proposed framework is unclear.

Throughout the preamble EPA uses language that mentions state agencies as delegated authorities. One such example is found at 87 FR 74750, *"The EPA further proposes that the entity making the report shall provide a complete copy to the EPA and to any delegated state authority (including states implementing a state plan) at an address those agencies shall specify."* The role of state agencies within the SERP must be more adequately defined. For example, as explained in these comments, the SERP program is not lawful or practically workable unless EPA takes a direct role in implementing the program (e.g., EPA must review and approve site-specific third-party monitoring plans, EPA must receive and vet the results of third-party monitoring and must decide whether the results are actionable). In the final rule, EPA must explain the process and degree to which these functions may reasonably be delegated to the states and, for functions that EPA determines are delegable, provide mechanisms to assure consistency among EPA's and the delegated states' programs.

2.0 Fugitive Emissions at Well Sites, Central Production Facilities and Compressor Stations

API supports the retention of NSPS OOOOa requirements for optical gas imaging (OGI) monitoring at well sites, central production facilities, and compressor stations. Except for multi-wellhead only well sites (see Comment 2.1), API also supports the proposed audio, visual, and olfactory (AVO) and OGI monitoring frequencies. In addition to the following comments concerning requirements for fugitive emissions at well sites, central production facilities, and compressor stations, API notes that EPA is not providing a meaningful opportunity to comment on a key basis for removing the wellhead only exemption because the underlying data for the Department of Energy (DOE) study[9] is unavailable.

2.1 API proposes AVO inspections only for all wellhead only sites.

EPA's focus on finding large fugitive emissions at single wellhead only sites using AVO inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. As EPA has already concluded, AVO inspections are a useful tool at

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[9] Bowers, Richard L. Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859

sites that lack extensive background noise and have field gas containing mixtures of methane and VOCs and condensate or produced liquids (87 FR 74727)[10]. Not only do wellhead only sites match these criteria, but their emission points are closer to ground level compared to other sites. For these reasons, out of all well site configurations, AVO is expected to perform the best at wellhead only sites, and it generally can be applied more frequently than other leak detection methods. EPA appropriately concluded that *"the types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspection"* (87 FR 74729)[11]. Given the large number of wellhead only sites and EPA's focus in regulating fugitive emissions at these sites, quarterly AVO inspections are appropriate to detect fugitive emissions at any wellhead only site including single wellhead or multi-wellhead well sites.

The proposed leak detection method and frequency for any emission source should take into consideration the count and relative magnitude of emissions, among other factors. The number of wellhead only sites across the U.S. is estimated to be in the tens of thousands. The resource demand from any leak detection requirement on wellhead only sites using OGI or Method 21 quickly multiplies.

EPA notes that the DOE study "*demonstrates that fugitive emissions do occur from wellheads, and in some cases can be significant"* as the basis for regulating wellheads. Similarly, commenters indicated "the wellhead itself is a source of emissions" because "these well sites have other smaller equipment that leaks and malfunctions, with large emissions having been observed from these sites". While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall well site emissions. A study conducted over the Permian Basin determined that simple sites, such as wellhead only sites, experience median emission rates two orders of magnitude smaller than complex sites (0.03 kg/hr for simple sites vs 2.6 kg/hr for complex sites)[12]. CAMS contracted with Bridger Photonics to conduct aerial surveys performed in the Permian Basin (5,361 pieces of equipment on 1,450 facilities over 250 square miles). The project found that 2% of total detected emissions were from wells and 5% of total detections were from wells[13].

These studies demonstrate that the population average emissions from wellheads is not relatively significant and therefore chasing fugitive leaks from these sources will not be impactful compared to deploying resources to other contributing sources. Nevertheless, we recognize this does not preclude the potential for fugitive emissions from an individual wellhead. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Coupled with proposed requirements[14] for conversion to non-emitting pneumatic controllers at existing sites, the increased cost of additional OGI screening at these sites raises further concerns regarding premature shut-in of production and states' ability to preserve the remaining useful life of facilities.

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[10] On the other hand, AVO inspections are a useful tool for identifying when there are indications of a potential leak without the need for expensive equipment or specialized training of operators. For example, at sites that lack extensive background noise, a person would be able to hear if a high-pressure leak is present, which could present as a hissing sound. Field gas produced at well sites contains a mixture of methane and various VOCs, which have the potential to be detected by smell. Where the field gas contains a lot of condensate or other produced liquids, any resulting leaks would present as indications of liquids dripping or potentially puddles forming on the ground.

[11] The types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspections and would not require the use of OGI for identification. Therefore, the EPA evaluated a periodic AVO inspection and repair program for addressing fugitive emissions from single wellhead only well sites.

[12] Robertson, Anna M., 2020, New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, Environmental Science and Technology, 54(21), 13926-13934 https://pubs.acs.org/doi/10.1021/acs.est.0c02927

[13] https://methanecollaboratory.com/wp-content/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021_vFinal.pdf

[14] See Comment 7.0

EPA's basis for applying OGI to multi-wellhead only sites is centered around additional connection points and valves with generally smaller emissions (87 FR 74732)[15]. While this basis is true, the focus appears to be misguided. If the principal concern with a single wellhead only site is to find the rare, but possible, large emissions leak, then it should follow that the principal concern for a multi-wellhead only sites should also be the rare occurrence of large emission leaks because it is relatively more likely with more than one well-head. That is, what warrants more attention to a multi-wellhead only site should not be the potential for more small emission leaks, but the greater potential for a large emission leak. Any significant difference in emissions leak potential from a single wellhead only site versus a multi-wellhead only site is not likely to be because of a small emission leak.

More frequent monitoring may also be challenging since many existing wellhead only sites can only be reached on foot due to remote location and lack of lease road access. While we believe quarterly AVO is the appropriate frequency for all wellhead only sites, at a minimum, bimonthly AVO inspections only would also be acceptable as the monitoring requirement for multi-wellhead only sites.

2.2 The proposed definition of fugitive emissions component requires further clarification.

Several aspects of EPA's proposed definition of fugitive emissions component require further clarification.

- **In yard piping should not be included in the definition of fugitive emissions component.** The inclusion of in yard piping as a fugitive emissions component expands that definition in unprecedented ways. Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.[16]
- **Definition should include thief hatches or other openings on a controlled storage vessel only.** Monitoring thief hatches and other openings on uncontrolled storage vessels adds no environmental benefit since the storage vessel emissions will be the same whether they are emitted from the tank vent or through thief hatches or other openings. Combined with the next item, fugitive emissions component should include thief hatches or other openings on a controlled storage vessel that is not subject to NSPS OOOO, OOOOa, or OOOOb because of a construction/reconstruction/modification date on or before August 23, 2011, or a legally and practicably enforceable limit.
- **Definition should also include the appropriate references to NSPS OOOO and OOOOa.** As proposed, fugitive emission components include covers and closed vent systems and openings on storage vessels not subject to NSPS OOOOb requirements. Since EG OOOOc will be implemented over the coming years, the definition of fugitive emissions component should also include the appropriate reference to

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[15] Multi-wellhead only well sites. For wellhead only well sites with two or more wellheads, the EPA anticipates that the same large emissions source (i.e., surface casing valves) would be present. In addition to these valves on the wellheads have additional piping, and thus connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO.

[16] We note that EPA's rationale for adding yard piping to the definition of "fugitive emissions component" is that, "[w]hile not common, pipes can experience cracks or holes, which can lead to fugitive emissions." 87 Fed. Reg. at 74723. EPA explains that its proposal will "ensure that when fugitive emissions are found from the pipe itself that necessary repairs are completed accordingly." Id. EPA's proposal is vague and fails to provide an adequate opportunity to formulate meaningful comments because EPA does not explain how leak detection should be accomplished for "yard piping" as compared to other already-listed fugitive emissions components, where there are identifiable leak points (such as valve stems or flange interfaces) that are the target of monitoring. For example Section 8.3 of Method 21 (which applies to LDAR standards such as the one here that specify a concentration-based leak definition) explains that monitoring should be conducted "at the surface of the component interface where leakage could occur." Section 8.3 also includes detailed instructions for individual components (such as valves), where particular leak points are identified. In contract, there is no identifiable leak point for "yard piping" that reasonably would be the target of monitoring. In fact, using Method 21, there is no obvious way that the required monitoring could be conducted because of the expansive lengths of pipe where the sort of leaks that EPA seems to be concerned about might occur. Before finalizing a requirement to include yard piping in the definition of fugitive leak component, EPA must provide additional explanation of how the LDAR provisions would apply and provide an opportunity for public comment on that necessarily more specific proposal.

NSPS OOOO and OOOOa requirements. For that time period, a site could have storage vessels subject to NSPS OOOO or OOOOa and be subject to NSPS OOOOb fugitive monitoring. See Comment 12.5 regarding the proposed reconciliation of NSPS OOOO and OOOOa with NSPS OOOOb and EG OOOOc.

- **Existing clarifying language from NSPS OOOOa should be retained.** Since NSPS OOOOb proposes to allow natural gas-driven pneumatic controllers and pumps in limited circumstances (e.g., sites in Alaska without access to electric power), the existing language from the NSPS OOOOa definition should be retained to clarify what is considered fugitive emissions.

Based on the above clarifications, API offers the following suggested redline, which retains much of the current NSPS OOOOa definition, to the proposed definition of fugitive emissions component in NSPS OOOOb and EG OOOOc:

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411, §60.5411a, or §60.5411b, thief hatches or other openings on a controlled storage vessel not subject to §60.5395, §60.5395a, or §60.5395b, compressors, instruments, and meters~~, and in yard piping~~. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

2.3 Delay of repair requirements should be expanded.

Due to the hundreds of thousands of sites that would be subject to fugitive monitoring under NSPS OOOOb and EG OOOOc, EPA should expand the proposed delay of repair requirements in the following ways:

- **Consistent with the requirements for natural gas processing plants, EPA should allow for delay of repair due to parts unavailability.** NSPS VVa, incorporated by reference in NSPS OOOO and OOOOa for gas plants, allows for delay of repair beyond a unit shutdown if "*valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.*"[17] In the Preamble to the November 2021 Proposal[18], EPA recognized that operators of older equipment may experience delays in obtaining replacement parts. Given current supply chain issues and the larger number of well sites, centralized production facilities, and compressor stations, EPA should expand the current delay of repair requirements to include delays because of parts unavailability.
- **EPA should add other potential circumstances beyond an operator's control that would require a delay of repair.** Repairs may be delayed due to circumstances not currently listed in the rule. Specifically, there are seasonal constraints related to farming and/or endangered species where operators cannot bring a rig in or have surface disturbance. Delay of repair should be allowed for these unique situations.

Based on these items, API offers the following suggested redlines to §60.5397b(h)(3), which are based on existing regulatory language from NSPS VVa:

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[17] 40 CFR §60.482-9a(e)
[18] 86 FR 63174

(3) Delay of repair will be allowed:

(i) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel~~.~~;

(ii) If the necessary replacement part supplies have depleted and supplies had been sufficiently stocked before supplies were depleted, the repair must be completed as soon practicable, but no later than 30 days once the necessary replacement part supplies are available; or

(iii) If the necessary repair equipment cannot be brought to the site for reasons, such as lease restrictions for farming or seasons for endangered species, the repair must be completed as soon practicable, but no later than 30 days once repair equipment may be brought to the site.

2.4 Repair timelines should be consistent for leaks identified using AVO or OGI.

The repair timelines should be the same whether the fugitive emissions at well sites, centralized production facilities, and compressor stations are identified using AVO, OGI, or Method 21 because the necessary repair actions are agnostic to the detection method. In other words, operators should have the same time to make repairs regardless of leak detection method because the repair actions depend more on the leaking component rather than detection method.

EPA's stated reason for requiring shorter repair timelines is *"so that the monthly AVO inspections do not overlap the repair schedule"*[19]. This justification is insufficient for two reasons:

- As proposed, monthly AVO inspections would apply only to compressor stations. This overlap would not occur for bimonthly or quarterly AVO inspections at well sites and centralized production facilities.
- EPA has allowed repair timelines to overlap with inspection in other regulations. Under existing LDAR regulations, a component may be on delay of repair for multiple monitoring periods in certain circumstances.

While AVO is generally more effective at detecting larger emissions, the existing OGI repair timelines do not consider emission rate because OGI cannot quantify the leak rate. The same inability to quantify fugitive emissions also applies to AVO, and so EPA should have the same repair timelines for both detection methods. Finally, consistent timelines would also streamline compliance.

To address this concern, API offers the following suggested redline of §60.5397b(h):

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[19] 87 FR 74737

Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made ~~in accordance with paragraphs (h)(1)(i) and (ii) of this section.~~

~~(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using visual, audible, or olfactory inspection.~~

~~(ii) If you are complying with paragraph (g)(1)(i) through (iv) of this section, a first attempt at repair shall be made~~ no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than ~~15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and~~ 30 calendar days after the first attempt at repair ~~as required in paragraph (h)(1)(ii) of this section.~~

2.5 EPA should clarify depressurized equipment are exempt from fugitive emissions monitoring.

State rules, including New Mexico[20] and Colorado[21], exempt depressurized equipment[22] from fugitive emissions monitoring because leak surveys are not anticipated to result in emissions reductions at these facilities. Monitoring would resume once the site or equipment is back in service. EPA should provide a clear exclusion for these types of facilities or equipment under both NSPS OOOOb and EG OOOOc. One suggestion would be to model the regulatory language on the existing storage vessel out of service and return service requirements.

See also Comment 13.3.

2.6 Additional clarification is needed for the proposed definition of modification for a centralized production facility.

EPA's proposed definition of modification for the collection of fugitive emissions components at a centralized production facility presents a challenge since the operator of a centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility especially when the operator differs between the centralized production facility and the offsite wells that send production to it. The operator of the centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility since the upstream operator is typically only required to notify the centralized production facility operator when a new well is drilled and starts to send production to the gathering system. The upstream operator may not necessarily identify the specific centralized production facility. EPA may not have anticipated this scenario in proposing the definition of modification for the collection of fugitive emissions components at a centralized production facility.

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[20] 20.2.50.116.C(9) NMAC

[21] https://drive.google.com/file/d/1a3IJ74txUxJ241wgh-ZMRx0Rn7LV3z2V/view

[22] The CO regulations reference depressurized equipment, while the NM regulation references temporarily abandoned wells.

To address this concern, API suggests that the modification criteria for centralized production facilities be limited to "An increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility". This criterion is simple, clear, and aligned with the purpose and definition of a centralized production facility, which is to gather hydrocarbon liquid production into storage vessels. As such, API offers the following suggested redline of §60.5365b(i)(2):

> *For purposes of §60.5397b and §60.5398b, a "modification" to centralized production facility occurs when~~:~~ an increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility.*
>
> ~~*(i) Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;*~~
>
> ~~*(ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or*~~
>
> ~~*(iii) A well site subject to the requirements of §60.5397b or §60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.*~~

We also suggest EPA add clarification to the definition for central production facility that addresses custody transfer.

2.7 EPA's proposed well closure plan requirements present several technical and legal issues.

After reviewing EPA's proposed well closure plan requirements, API has identified the following technical and legal issues:

- **The proposed well closure plan requirements are duplicative with other regulations.** Well closure requirements are within the jurisdiction of State Oil & Gas Commissions and other agencies, not the EPA. Under state law, a well is required to be plugged and abandoned when it has reached the end of its useful life. In all States, operators must provide written notice of plugging and comply with regulatory requirements to plug and abandon the well, including removing equipment, setting downhole plugs, cementing in the casing, capping the well to prevent fluid migration and restoring the surface site. These practices are done to permanently confine oil, gas and water into the strata in which they were originally found. For wells located on federal lands, separate BLM requirements also apply for well closure. Depending on the well location (e.g., located in an area with potash mining), additional requirements may also apply. For some wells, EPA would be adding a fourth set of well closure requirements.

  Therefore, EPA's proposed notifications and well closure plan requirements are duplicative, unnecessary, and increase administrative burden while providing no discernible accompanying environmental benefit when an operator is working to properly close a well. In certain cases when an emergency plugging is required, the proposed notification timelines may be impossible to meet.

- **EPA does not have the technical expertise to review well closure plans.** State Oil & Gas Commissions have the technical knowledge to evaluate well closure plans, because they have the jurisdiction for well closure. Without the technical knowledge, EPA's proposed well closure plan requirements require

significant operator and agency resources but provide no additional environmental benefit. Operators should only be required to maintain records of an approved well closure plan by the state authority with jurisdiction; these records could be provided to EPA upon request.

Under existing State and BLM requirements, well closure plans include detailed information on the well casing, tubing, and rod dimensions, perforation depths, proposed plug materials, depths, tagging, and verification, leak testing for cast iron bridge plug (CIBP), and other required data.

- **EPA does not have authority under CAA § 111 to impose financial assurance requirements.** Part of the proposed well closure plan is a "description of the financial requirements and disclosure of financial assurance to complete closure". This requirement is clearly beyond EPA's authority under the Clean Air Act (CAA). For more details, refer to Comment 12.8.

- **The proposed requirements may create unforeseen liability consequences.** EPA has not clarified how the proposed well closure requirements will transfer with ownership. Under State and BLM rules, chain of title is defined. EPA should not create duplicative requirements that could create potential liability consequences for operators.

- **The notification prior to well closure should be removed. If EPA finalizes the proposed well closure requirements, EPA must clarify when a well closure plan is required to be submitted.** Language at §60.5397b(l) potentially conflicts with §60.5420b(a)(4) in terms of whether a well closure plan needs to be submitted every time that production ceases for more 30 days or only when the operator intends to close the well and stop fugitive emission monitoring. "Cessation of production" is not defined in the proposed regulations. A 30-day period from cessation of production is not indicative of well closure. Operators may have many instances where wells are shut-in for periods of 30 days or more, with complete intent to return the wells to production. A few examples include a facility undergoing maintenance or repair, shut-in for offset fracturing, lack of access to gathering, or wells on cycled production. We request EPA clarify that the well closure plan requirements and notification only when operators intend to permanently close the well and stop fugitive monitoring.

Overall, API recommends that requirements within NSPS OOOOb and EG OOOOc pertaining to well closure be limited to the following:

- **A recordkeeping requirement to maintain records of an approved well closure plan by the local authority with jurisdiction.** This recordkeeping only requirement would avoid unnecessary and duplicative requirements with State Oil and Gas Commissions. The records could be submitted to EPA upon request.

- **A final OGI survey to confirm no detected fugitive emissions after well closure.** EPA could still require a final OGI survey after well closure.

3.0 Alternative Leak Detection Technologies including Periodic Screening and Continuous Monitoring

API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA

to make key adjustments in the final rules to enhance the use of these technologies and to not unintentionally disincentivize development and deployment of these technologies. Making alternative technologies more accessible in these rules can also have synergistic benefits with measurement-informed inventory goals in related rulemaking such as the Inflation Reduction Act's Methane Emissions Reduction Program and EPA's Greenhouse Gas Reporting Program.

These adjustments are described in our comments below, including initial comments on EPA's FEAST modeling. While API is exploring additional modeling analyses, due to the short comment period, any additional modeling analysis may be provided in a subsequent submittal. We welcome the opportunity for future discussions on this important topic with EPA staff.

3.1 Comments Regarding Both Periodic Screening and Continuous Monitoring Technologies

3.1.1 Technologies should be available for use upon finalization of NSPS OOOOb and EG OOOOc.

To facilitate adoption of alternative leak detection technologies, operators need options available beginning with finalization of the proposed rules. EPA's proposed 270-day review timeline means that technologies would likely not be approved until after the first AVO, OGI, or Method 21 inspection, since the initial inspection would be required 90 days after NSPS OOOOb is finalized. This gap may disincentive the use of alternative technologies as operators would already be required to implement the standard fugitive emissions monitoring program with AVO, OGI, and/or Method 21 inspections.

Recognizing that EPA is unable to approve technologies until the rules are finalized, API proposes that alternative technology applications be granted conditional approval if they are submitted within 90 days after the final rule is published in the Federal Register (based on the proposed timelines for the initial AVO, OGI, or Method 21 surveys). This initial conditional approval period would allow for the immediate use of those alternative technologies to achieve initial compliance with NSPS OOOOb. An alternative to initial conditional approval could be extending the deadline for initial monitoring surveys from 90 day to one (1) year in §60.5397b(f) and §60.5398b(b)(2). Time beyond the 270-day conditional approval would be needed for operators to contract with vendors and conduct the initial surveys.

Operators would be able to use the conditionally approved technologies until EPA provides written disapproval to the requestor. Disapproval of a conditionally approved technology should not be considered a deviation for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology. EPA has already proposed the idea of conditional approval for alternative technologies, so this idea could be extended to allow for technologies to be available for initial compliance. EPA could also utilize technologies approved by a state or another country (e.g., Colorado or Canada) as a starting point for initial conditional approval.

In place of or in addition to initial conditional approval, API recommends that EPA prioritize review of initial alternative technology applications (submitted within 90 days after final rule is published in Federal Register) based on the following criteria:

- The technology is already approved for use by a state or another country. Approval by another agency means that the technology has been reviewed previously and is likely to meet EPA's proposed minimum detection threshold of ≤ 30 kg/hr (based on a probability of detection of 90%) as shown in Table 1 and Table 2 to NSPS OOOOb.

- The technology is already used by one or more operators for monitoring under voluntary efforts or regulatory programs. One potential measure could be the number of sites monitored in 2022 using the alternative technology under voluntary efforts or other regulatory programs.

An initial conditional approval period and prioritization of review would allow for quicker adoption of alternative technologies and would also alleviate pressure from EPA to review a potential influx of applications upon rule finalization. Without these measures, EPA could be overwhelmed with applications, and the full 270-day review period would pass before the first technologies would be conditionally approved.

3.1.2 EPA should clarify how the review and conditional approval process will be implemented.

We request EPA provide the following clarifications regarding the application review and conditional approval process for use of alternate technologies:

- EPA should clarify that operators are able to use conditionally approved technologies until EPA provides written disapproval to the applicant.
- EPA needs to consider how to effectively notify operators when a conditionally approved technology is disapproved.
- EPA should also clarify that disapproval of a conditionally approved technology should not affect compliance for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology.

EPA should also elaborate on how deficiencies in an application will affect the proposed review timelines. For the initial 90-day review and final 270-day review, the proposed regulatory language implies that deficiencies in an application will result in disapproval and require the applicant to revise its request and restart this process. As with other application processes, agencies will typically issue requests for additional information with appropriate deadlines so that applicants can resolve deficiencies without restarting the entire application process. Forcing applicants to restart the process for any application deficiency would further delay the approval of alternative technologies for use by operators.

3.1.3 Emissions detected from covers and closed vents systems using alternative technology or while doing required follow-up surveys do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

As discussed in more detail in Comment 5.1 , emissions detected from covers and closed vent systems are not necessarily violations of the "no identifiable emissions" standard since it is a work practice standard rather than a numerical zero emission standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through alternative technology or a required follow-up survey triggers the

obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented. Treating emissions detected from covers and closed vent systems as violations not only fails to acknowledge technical reality contrary to best system of emission reduction (BSER), but it also disincentivizes the use of alternative technology.

3.1.4 While API appreciates EPA providing modeling, EPA's current model overestimates the effectiveness of AVO and OGI.

We appreciate EPA's efforts to create a technology-agnostic, performance-based alternative test method framework supported by an underlying, publicly available FEAST model. In EPA's model, the probability of detection curves for AVO and OGI have 100% probability of detection for leaks above approximately 200 g/hr and 60 g/hr, respectively. While these are useful detection methods in various applications, these characterizations overestimate their effectiveness in certain field conditions and leads to impractical performance standards for the alternative technologies as discussed further in Comment 3.3.1 for periodic screening and Comment 3.4.5 for continuous monitoring.

For example, AVO inspections are less likely to find large leaks if they are located above the person performing the inspection, they occur in areas that the person cannot enter due to safety concerns (e.g., potential for H_2S exposure), or they are located in areas with high noise among other reasons. While 60 g/hr is the current NSPS OOOOa and proposed NSPS OOOOb and EG OOOOc standard for OGI cameras, probability of detection for OGI also depends on the camera operator and field conditions.[23] A more realistic characterization of AVO and OGI detection methods would create a more realistic equivalency model for alternative technologies. Due to the short comment period, we may continue to analyze EPA's assumptions about intermittency of leaks, model plant configurations (i.e., equipment types and component counts), and leak occurrence in subsequent comments.

3.1.5 The alternative technology framework should allow flexibility in conducting leak surveys due to seasonal challenges.

The alternative technology framework should allow for flexibility in conducting AVO/OGI and screening surveys due to seasonal challenges and weather events. Some examples include but are not limited to:

- Snow cover can adversely affect the ability of some alternative technologies to detect methane during part of the year.
- High winds can also prevent aerial-based technologies from being deployed on certain days.
- Weather events such as hurricanes may limit the ability to deploy OGI camera operators to sites for surveys.

The alternative technology framework should allow different technologies to be deployed at appropriate frequencies throughout the year. The deadline for the next survey would be based on the type of site and the last survey conducted. As an example, at single wellhead only site, an operator could conduct AVO inspections for the first two quarters of the year followed by a screening survey at ≤ 2 kg/hr and then another AVO inspection no later than four months after the screening survey, based on EPA's proposed requirements. Flexibility in applying alternate screening technologies should include provisions that use of a different technology than originally

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[23] Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. *Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions*. Environmental Science & Technology 2020 54 (18), 11506-11514 DOI: 10.1021/acs.est.0c01285

planned (due to weather or other external factors) constitutes an allowance, not a deviation from an operator's monitoring plan.

3.1.6 Framework for alternative leak detection technologies should allow multiple technologies, including satellite, to be combined. More combinations of technologies should be added to the proposed periodic screening matrices.

Overall, API believes that allowing the use of a combination of alternative leak detection technologies can be effective to find and fix leaks. This alternative approach recognizes that each leak detection technology (AVO, OGI, Method 21, periodic screening, or continuous monitoring) has strengths and weaknesses in terms of detection threshold, proximity to the source, localization performance, deployment frequency, and costs. For example, ground-based OGI has a low detection threshold and localizes the leak to a particular component but requires proximity to the source and is infeasible to deploy at higher frequencies. Whereas satellites, aerial and continuous technologies can be deployed more frequently than ground-based OGI, the increased distance from the source may not detect leaks on the component level. With these remote detection technologies, resources can be deployed more efficiently to repair leaks – operators would only need to visit sites with detected emissions to make repairs whereas using only OGI surveys require operators to visit each site but could result in no detected emissions. A continuous monitoring system can quickly detect a leak and depending on sensor location, provide an approximate location, but may not fully visualize its location like a plume map from a satellite or aerial survey. In other words, no individual leak detection technology offers a perfect solution.

By allowing the option for a combination of these various technologies into a single monitoring plan or framework, the weaknesses of one technology can be offset by the strengths of another, and the selected technologies work together to improve leak detection and reduce emissions in a flexible and cost-effective manner. Technologies can be combined such that larger emissions are quickly detected, and technologies that detect smaller emissions are deployed less frequently. Finding and fixing the biggest leaks quickly can greatly impact the overall emission reductions.

A multi-layered approach for leak detection combines various technologies to achieve greater emission reductions. Some fugitive emissions may be detected with traditional OGI or AVO during regular LDAR inspections. Intermittent emissions are not always detected during OGI or AVO inspections; however, they may be detected by a continuous monitoring system. Deploying continuous monitors is not an option for all sites, such as those without access to reliable grid power. Alternatively, an aerial survey may detect emissions from such sites over a large area. Although satellites cannot always detect emissions at the component level, they can be useful for basin-wide detection of large emissions that may occur outside of scheduled inspections. This concept of layering various leak detection technologies is illustrated in the graphic below where lines and layers represent strengths of a given technology while the dashed circles represent weaknesses allowing undetected emissions. An example of this multi-layered approach using data from the Permian Basin can be found in an industry pre-publication paper[24].

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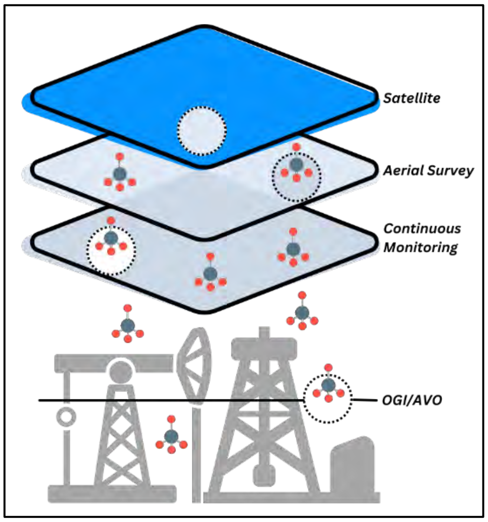
[24] Cardoso-Saldaña FJ. *Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities*. ChemRxiv. Cambridge: Cambridge Open Engage; 2022; This content is a preprint and has not been peer-reviewed. DOI: 10.26434/chemrxiv-2022-f7dfv

Figure 1. Multi-layered Approach for Leak Detection



EPA has already included the idea of layering technologies with the screening survey plus annual OGI survey options in the periodic screening matrices. API has two specific suggestions regarding an alternative multi-layered approach for leak detection:

- **API recommends that continuous monitoring (see also Comment 3.4.1) and satellite technology be included as options directly in the matrices in combination with the periodic survey with and without annual OGI.** In other words, combinations like “Quarterly + Weekly Satellite + Annual OGI”, “Quarterly + Weekly Satellite”, “Quarterly + Continuous + Annual OGI”, and “Quarterly + Continuous” should be modeled and added to the periodic screening matrices with appropriate detection thresholds for the screening technology. Satellite technology would be defined with a ≤ 100 kg/hr detection threshold and a weekly frequency. Having frequent satellite surveys will allow reducing the number of periodic surveys per year for a given detection threshold with and without an annual OGI survey.

- **Separately, we would also welcome an additional optional and flexible framework independent from the periodic screening matrices and case-by-case AMEL process where an operator can develop a monitoring plan for each basin/site with their chosen suite of EPA-approved technologies via EPA-approved modeling.** Similar to EPA’s proposed clearinghouse approach to approving alternative screening technologies, EPA could evaluate and approve different modeling platforms for use in developing monitoring plans. Modeling could be refined over time based on data generated through the monitoring plan. The initial modeling should represent the highest emissions level since emissions should decrease over time as NSPS OOOOb and EG OOOOc are implemented over the next several years. This approach would both allow the technology to mature over time and a streamlined approach to alternative modeling compared to the existing case-by-case AMEL process.

  This flexible framework gives operators a clear pathway for a custom, fit-for-purpose option and would be an alternative to both the AVO/OGI requirements and alternative technology requirements. To benefit smaller operators, EPA should consider both a conservative, and realistic, default plan that allows for flexibility in monitoring technology as well as an option where an approved monitoring plan can be used by other operators with similar assets.

3.1.7 Repair timelines should be consistent for leaks using AVO/OGI or alternative leak detection technologies.

Recognizing that repair timelines are part of the overall effectiveness of a leak detection program, API recommends that repair timelines be consistent between traditional (AVO, OGI, or Method 21) and alternative (periodic screening or continuous) leak detection programs. Repair actions depend more on the leaking component rather than detection method. The proposed repair or corrective action timelines in §60.5398b(b)(4) for periodic screening and §60.5398b(c)(6) for continuous monitoring are shorter than those in §60.5397b(h) for fugitive emissions components and §60.5416b(b)(4) for covers and closed vent systems. The shorter repair timelines for alternative leak detection technologies may disincentivize their use. Consistent repair or corrective action timelines would streamline compliance and facilitate the use of multiple technologies. If EPA chooses to finalize shorter repair timelines for alternative technology, API recommends that repairs be prioritized based on higher detected emissions.

3.1.8 EPA should allow operators to use alternative technology to comply with NSPS OOOOa without an AMEL.

Since the proposed NSPS OOOOb fugitive monitoring requirements including alternative technology are at least as stringent as the existing NSPS OOOOa requirements, EPA should allow operators use of alternative technology for NSPS OOOOa compliance without going through the Alternative Means of Emission Limitations (AMEL) process or waiting for state plans to be fully implemented under EG OOOOc. Both the AMEL process and EG OOOOc state plan implementation could take years. EPA can make the NSPS OOOOb alternative technology a compliance alternative for NSPS OOOOa since EPA is planning to update certain aspects of NSPS OOOOa in conjunction with this rulemaking. This addition should not require further notice since the requirements are at least as stringent as the existing NSPS OOOOa requirements. Some alternative technology (e.g., aerial surveys) is deployed over a particular basin or portion thereof and could include both NSPS OOOOa and OOOOb sites. Therefore, allowing the use of alternative technologies for NSPS OOOOa compliance without an AMEL would further incentivize the adoption of these emerging technologies.

3.2 The term “investigative analysis” should replace “root cause analysis”.

The specific term “root cause analysis” has other meanings and specific denotations in various regulations and in the oil and gas industry. There is also a legal issue with how this term can be interpreted in any legal or enforcement proceedings, as well as how it could obligate operators to actions or additional requirements that are not necessarily included within this proposed rule.

API understands and supports EPA’s intent for investigating why certain emission events or leaks have occurred, but recommends the removal of the term “root cause analysis” and replacement with the term “investigative analysis” within NSPS OOOOb and EG OOOOc.

We offer additional comments specific to how “root cause analysis” has been proposed with respect to the super-emitter response program in Comment 1.1.6.

3.3 Comments Specific to Periodic Screening Technology

3.3.1 Proposed periodic screening matrices do not incentivize the use of the alternative technology.

While API acknowledges EPA's proposed matrices of minimum detection thresholds and frequencies, they do not incentivize the use of alternative technology as proposed. To have the same monitoring frequency as OGI, alternative technology must have a minimum detection threshold of ≤ 1 kg/hr for both quarterly OGI and semiannual OGI requirements. This proposed performance level effectively limits the alternative technology options as operators are more likely to use technology with the same or less frequent monitoring than OGI. The proposed performance standards in the matrices are more stringent than needed in part because EPA's FEAST model overestimates the effectiveness of AVO and OGI inspections as mentioned previously in Comment 3.1.4. To incentivize the use of alternative technologies, API believes that quarterly screening surveys with an annual OGI survey should equate to a minimum detection threshold of ≤ 10 kg/hr for sites subject to quarterly OGI; the rest of the matrices would be adjusted accordingly. Supporting modeling analysis may be provided in subsequent comments.

These matrices also do not appear to be based primarily on the minimum leak detection threshold. In proposed Table 1 to Subpart OOOOb of Part 60, the minimum detection threshold is proportional to screening frequency between monthly and bimonthly frequencies without annual OGI (i.e., minimum detection threshold is halved for twice as frequent monitoring). However, if an annual OGI survey is included with monthly and bimonthly screening surveys, the minimum detection threshold is decreased by a factor of 3 instead of the expected 2 (i.e., monthly + annual OGI requires 30 kg/hr detection while bimonthly + annual OGI requires 10 kg/hr instead of the expected 20 kg/hr). While frequency and detection threshold are not the only parts of a leak detection program, one would expect frequency and detection thresholds to be roughly proportional assuming that other aspects of the leak detection program (e.g., repair timelines) are constant.

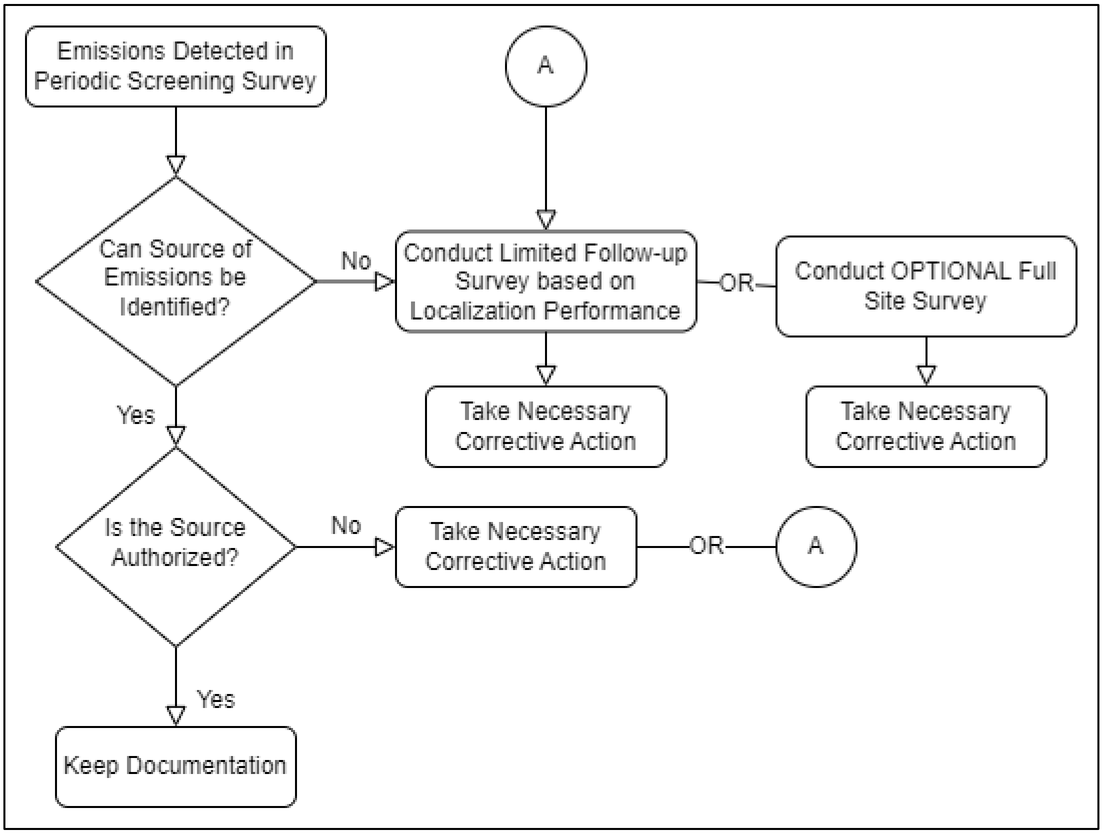
3.3.2 Proposed follow-up actions for periodic screening surveys should be revised.

As discussed in Comment 3.1.7, proposed repair or corrective action requirements for alternative technology should not disincentivize their use. API supports that a full site follow-up OGI survey fulfills the annual OGI survey requirement (where applicable) as indicated in §60.5398b(b)(3)(iii). Regarding the proposed requirements for periodic screening in §60.5398b(b)(4), API offers the following suggestions:

- **The requirements on receiving results of periodic screening and conducting follow-up surveys should be separated from other repair requirements to avoid confusion.** The language in §60.5398b(b)(4) implies that receiving periodic screening results and conducting follow-up surveys are repair requirements when they are both monitoring requirements to detect or confirm leaks.
- **The timeline for receiving results of periodic screening should be extended from 5 calendar days to 5 business days.** Periodic screening surveys can cover hundreds of sites, and so vendors and operators need additional time to process the data for further action.
- **Follow-up surveys and inspections should be limited to sites where the source of emissions cannot be identified based on the localization performance of periodic screening results and other operational information.** Follow-up OGI surveys and cover and closed vent system inspections should not be required if the source of detected emissions can be identified based on the localization performance of the

alternative technology and/or other data. Alternative technology has varying degrees of localization performance in terms of being able to identify emissions on the site-level, equipment group-level, equipment-level, or component-level. Our proposed follow-up action process gives operators the necessary flexibility in responding to detected emissions and is presented in Figure 2and described in detail below.

Figure 2. Flowchart of Proposed Follow-up Actions for Periodic Screening Surveys



When emissions are detected in a periodic screening survey, the operator first tries to identify the source of emissions from the survey results and other available information. For safety and cost reasons, follow-up surveys in the field should be limited to situations where additional information is needed to identify or confirm the source of detected emissions. If the source of detected emissions can be identified, next steps would be based on the type of source.

- If the source of emissions is permitted or otherwise authorized, including maintenance activities, no further action would be required other than to keep documentation. Examples include, but are not limited to, engine or turbine exhaust, uncontrolled storage vessel, planned compressor blowdown, planned engine or turbine startup or shutdown, or properly operating control device. This situation is especially important to compressor stations where periodic surveys are likely to detect emissions from sources operating in compliance with applicable requirements.
- If the source of emissions is a process upset, leak, or other unauthorized release, the operator should be able to directly take necessary corrective actions rather than spending time and effort on a follow-up survey to confirm the source. Taking direct action with the appropriate timelines reduces emissions faster than conducting a follow-up survey first. If the operator determines that a follow-up survey is appropriate to confirm the source of detected emissions, they should be

able to conduct one based on the localization performance of the technology or an optional full site survey.

If the source of detected emissions cannot be identified, operators would conduct a follow-up survey limited to the localization performance of the alternative technology or conduct a full site survey to satisfy the annual OGI survey requirement (if applicable). If two or more full site surveys are conducted within a 12-month period, the most recent full site survey would determine the deadline for the next required annual OGI survey (if applicable). As an example, an alternative technology that can only detect leaks on the site level would require a full site survey while one that can detect leaks down to the equipment would require follow-up surveys only on equipment with detected leaks. Requiring a full site survey anytime that emissions are detected from periodic screening surveys is practically the same monitoring requirement as the primary AVO/OGI requirements but with the additional cost of conducting periodic screening surveys. Due to the large volume of data that can be generated from periodic screening surveys, limited follow-up surveys allow OGI resources to be used in a focused and cost-effective manner. Limited follow-up surveys could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to a full follow-up survey required for every time emissions are detected during a periodic screening survey.

- **Repair timelines should be consistent with AVO/OGI requirements.** Repair timelines should be consistent between traditional and alternative leak detection programs to streamline compliance and facilitate the use of multiple technologies. Therefore, the language in §60.5398b(b)(4)(iii) should simply reference the appropriate repair requirements for fugitive emissions components and covers and closed vent systems.

- **The proposed investigative analysis for control devices in §60.5398b(b)(4)(iv) and covers and closed vent systems in §60.5398b(b)(5) should be initiated within 5 business days.** While API recognizes the importance of proper control device and cover and closed vent system operation, we propose that the investigative analysis be initiated within 5 business days of either receiving the periodic screening survey results in the case that the control device, cover, or closed vent system can be identified as the source of emissions or conducting the limited or full site follow-up survey, whichever is later. This proposed timeline would be consistent with the framework we propose for the SERP in Comment 1.1. EPA's proposed 24-hour timeline is too short to be practical.

- **The proposed investigative analysis for covers and closed vent systems in §60.5398b(b)(5) is more stringent than the repair requirements under §60.5416b(b)(4) and should be removed.** As proposed in §60.5398b(b)(5), a leak or defect in a cover or closed vent system detected by follow-up inspections would require additional analysis beyond repair, including a determination of whether it was operated outside of its design. A leak or defect in a cover or closed vent system detected by routine inspections would be subject only to repair under §60.5416b(b)(4). The investigative analysis for covers and closed vent systems under the alternative technology requirements goes beyond the primary standards, and so §60.5398b(b)(5) should be removed.

- "**Root cause analysis" should be replaced with "investigative analysis".** Consistent with Comment 3.2, the term "investigative analysis" should replace "root cause analysis" in §60.5398b(b)(4)(iv) and §60.5398b(b)(5) (if that requirement remains).

3.4 Comments Specific to Continuous Monitoring Technology

We support EPA's inclusion of continuous monitoring in §60.5398b(c), and our members believe there is great potential in the use of continuous / near-continuous methane monitoring technologies. However, some of the proposed elements are problematic for practical implementation and use of continuous monitors. Therefore, we offer the following comments to craft a more functional continuous monitoring program based on the types of monitors that currently exist, focused on the desired outcome of detecting methane emissions at oil and natural gas production facilities to identify necessary response or repairs, if warranted.

3.4.1 The use of continuous monitoring technology within the periodic screening matrices must be clarified.

The proposed rule language is unclear whether continuous monitoring technology could also be used under the periodic screening survey requirements in §60.5398b(b) and associated matrices. For continuous monitoring technology that simply detects rather than quantifies methane emissions, these technologies could be used for periodic screening surveys. In these situations, the continuous monitor acts like a smoke alarm to notify operators of potential issues. Since continuous monitors can be used more frequently than monthly, EPA should consider adding a more frequent tier or a separate continuous monitoring row to the matrices. The equivalent emission reductions from continuous monitoring could be demonstrated through appropriate modeling. **We recommend incorporating continuous monitoring into the alternative screening matrix for the reasons discussed and to streamline inclusion into the monitoring plan framework we have described in Comment 3.1.6.**

3.4.2 The framework for continuous monitoring should be designed with both fenceline and within-the-fenceline technologies in mind.

As written, EPA's proposed requirements for continuous monitoring appear to be designed for fenceline technology. EPA should clarify that both fenceline and within-the-fenceline technologies can be used and provide details on how implementation would differ between them. API fully expects continuous monitoring technology for methane detection to come within the fenceline and get closer and closer to the source, unlocking emissions reduction potential that is unlikely to be realized by sensors installed on the perimeter. These within-the fenceline technologies will not have many of the limitations of today's fenceline solutions – including no need for wind or meteorological data because these sensors will be in closer proximity to equipment. Limiting the continuous monitoring requirements in this rulemaking to fenceline only would potentially reduce incentives to develop more advanced technology.

3.4.3 Currently available continuous / near-continuous monitoring technology detect methane emissions. The requirement for quantification should be amended.

Current continuous or near-continuous monitors are used to detect emissions and allow for a real-time response by operators; however, these monitors are not and should not be treated as a continuous emission monitoring system like a more traditional "CEMS". These monitors are "high frequency" monitors and not necessarily "continuous" in a traditional sense. The main focus of the monitors should be in the detection of emissions similar to the current OGI framework where the technology is used to find a leak and an operator can then respond, and if appropriate, to fix the leak.

The proposed framework should not be limited by a technology's ability to quantify emissions as this severely limits the types of monitors that can be used and offers a disincentive for operators to deploy the high frequency monitors currently available for deployment. Many technologies on the market today purport to quantify, but industry experience is that the value and accuracy is driven by the system's ability to act as a smoke alarm, where a certain threshold triggers a response system that notifies operators. There is no continuous monitoring technology today that actually "measures" a rate. The "quantification" capability is not derived from the underlying "smoke alarm" sensor but layering that sensor with wind, meteorological and other plume model / inversion model information / assumptions, which has untenable uncertainty.

Therefore, we believe these types of monitors should be considered as effective as the BSER standard, which is quarterly OGI for many larger well sites, central production facilities, and compressor stations. This proposal would have the technologies follow an approach similar to the matrix for other alternate technologies provided in §60.5398b(b) and Tables 1 and 2 to Subpart OOOOb and not follow the action levels in §60.5398b(c).

3.4.4 Continuous / near-continuous monitors should be evaluated against BSER, which is quarterly OGI.

As mentioned, currently available monitors allow for an alarm and response framework that allows operators the ability to evaluate the alarm and mitigate potential leaks. Due to this, continuous monitoring should be compared against the effectiveness of the technology in allowing response and potential repair of leaks against the BSER requirement of quarterly OGI and not based on the type of "fenceline" type framework that has been proposed. Per §60.5398b(c)(1), EPA has defined continuous monitoring as **"***the ability of a measurement system to determine and record a valid methane mass emissions rate of affected facilities at least once for every twelve-hour block."* This equates to daily scans at the facility, which sets an unrealistically high bar for implementation when compared against BSER that sets the most stringent monitoring at quarterly OGI and monthly AVO. The use of high frequency monitors should be consistent with BSER based on the detection capabilities of the monitors.

3.4.5 If EPA keeps its proposed framework for continuous monitoring, the proposed action levels should be revised.

While API overall recommends that continuous monitoring be incorporated with periodic screening to create a single framework for alternative technology, we have concerns with the proposed action levels if EPA choose to keep its proposed separate framework for continuous monitoring. The proposed action levels are based on EPA's FEAST modeling, which does not accurately characterize the effectiveness of AVO and OGI as discussed in Comment 3.1.4. We see merit in including a framework for future technologies that could detect and more accurately quantify emissions, but the currently proposed thresholds are not reflective of actual operations.

Regarding the proposed action levels in §60.5398b(c)(4), API offers the following suggestions:

- **Action levels should be based on detected emissions above an established baseline.** As proposed, the action levels appear to be based on total site emissions, which includes routine or baseline emissions, rather than emissions above an established baseline. Under continuous monitoring, fugitive emissions from leaks are additive to baseline emissions, but they are not additive under AVO/OGI/Method 21 and periodic screening programs. Action levels based on total site emissions effectively sets a limit on site emissions without considering the size or number of emission sources at a site, which could disincentivize the use of continuous monitoring, especially at larger sites. Also, failure to consider baseline emissions

would not exclude contributions from other nearby sources of methane emissions including but not limited to other sites, farming activities, graywater trucks, human populations, etc. EPA should revise the action levels to be based on emissions above baseline and propose how operators establish those baseline emissions.

- **The rolling 90-day (long-term) action levels should be removed as they have no equivalent in the AVO/OGI/Method 21 or periodic screening requirements.** Both the AVO/OGI/Method 21 and periodic screening programs require action to address emissions detected during the monitoring; in other words, emissions are compared to an established immediate or short-term threshold. Neither program has a long-term emissions threshold for action like the rolling 90-day action levels proposed for continuous monitoring. A long-term action level is at best a lagging indicator of an event and would make the investigative analysis of an exceedance more challenging. EPA has not clarified how operators should treat exceedances of the short-term action level that could also cause an exceedance of the long-term action level; operators resolve the short-term event in a timely fashion but may still exceed the long-term action level without any additional events or leaks. Based on these various reasons, EPA should either incorporate continuous monitoring completely into the screening matrix or remove the long-term action levels from the separate continuous monitoring framework.

- **The rolling 7-day (short-term) and rolling 90-day (if they remain) action levels should be revised.** The proposed action levels are too low and therefore practically disincentivize the use of continuous monitors. Despite being the most frequent detection method (every 12 hours as proposed), the proposed short-term action levels of 15 or 21 kg/hr are both below 30 kg/hr, which is the detection threshold for the most frequent periodic screening technology (monthly). A typical minimum threshold for actionable detection and notification is 20 kg/hr for today's technology. The lower the action level, the higher uncertainty on which source is causing the detection, and the likelihood for monitors to detect permitted or other background emissions. One potential solution is to have the short-term action level based on a fixed level to address smaller sites (e.g., wellhead only sites) or a variable level from baseline emissions (e.g., 200% of baseline emissions) to address larger sites.

  The long-term 1.2 or 1.6 kg/hr action levels may also be below the baseline emissions for many sites, which would be especially problematic if they represent total site emissions. Some operators, therefore, would effectively be unable to adopt continuous monitoring for NSPS OOOOb or EG OOOOc compliance.

3.4.6 We support timely and flexible follow-up actions to address any leaks found and request similar repair timeframes consistent with §60.5397b and §60.5416.

API supports the flexible language proposed in §60.5398b(c)(6) that describes initiating an investigative analysis to determine the primary reason for the emissions detected. We believe an operator can perform this investigation in numerous ways including using site-specific data. Due to the various ways that continuous monitors may be used for emissions detection, different follow-up actions may be appropriate for this technology when compared to AVO, OGI, or Method 21. While we appreciate the flexibility, we offer the following suggestions so that follow-up actions do not disincentivize the use of continuous monitoring as discussed more generally in Comment 3.1.7:

- **The timeline for initiating the investigative analysis should be extended from 5 calendar days to 5 business days.** Similar to periodic screening, additional time is needed for data validation.

- **EPA should clarify that the investigative analysis and corrective actions can be conducted remotely where feasible.** Operators should be able to conduct an initial evaluation of detected emissions based on SCADA or other operational data rather than sending a person to the site. Due to safety and cost concerns, operators typically limit the amount of time in the field. Remote investigative analysis and corrective actions could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to an onsite analysis required for each instance of detected emissions.

- **EPA should also clarify that limited or full site follow-up OGI surveys should be allowed in response to emissions detected by continuous monitoring depending on the localization performance of the continuous monitor(s)**. A limited or full site follow-up OGI survey may be a useful tool in identifying the source of emissions and therefore appropriate corrective actions. API recommends that the proposed follow-up action process for periodic screening surveys based on localization performance also apply to continuous / near continuous monitoring; refer to Comment 3.3.2 and Figure 2 for more details.

- **The timeline for completing the investigative analysis and initial corrective actions should be 30 days, not 5 days as proposed.** Follow-up actions for continuous monitoring should be consistent with repair timelines for OGI inspections.

- **Consistent with our suggestions in Comment 3.2, we suggest all references to “root cause analysis” be amended to “investigative analysis”.**

4.0 Associated Gas Venting from Oil Wells

API recognizes the environmental benefit of eliminating the venting of associated gas from oil wells that do not currently recover gas to a sales line, for injection, or for onsite fuel as its primary use. We disagree with EPA’s approach to the control standards proposed including the level of recordkeeping and reporting as it far exceeds the normal level of compliance assurance typically expected from an NSPS. An initial analysis[25] of the impact of the rule on potential production indicates that if the final rule were to eliminate flaring of associated gas, or is implemented in such a way that the practical effect is to eliminate flaring of associated gas, it could result in a substantial loss to production. Such a restriction or implementation would not be supported by API. Should the final rule either expressly or practically eliminate flaring of associated gas, it could be technically infeasible and not cost effective.

We offer the following suggestions with the belief that it is possible to create a manageable regulatory framework that targets the emissions from associated gas at areas without gas gathering infrastructure, including practical compliance assurance, recordkeeping, and reporting.

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[25] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API's request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

4.1 We support recovering gas to sales, for reinjection, used as onsite fuel, or routing gas to a control device. We do not support the additional certifications against emerging technologies prior to flaring associated gas.

We continue to support how EPA had described the proposed requirements for associated gas from oil wells in their November 2021 preamble description, but we do not support the hierarchy of the compliance options and associated recordkeeping and reporting requirements as proposed and believe the requirements should be technology neutral. Specifically, we support:

- Recovering gas to sales in §60.5377b(a)(1) (see also Comment 4.2).
- The beneficial use of the associated as onsite fuel proposed in §60.5377b(a)(2).
- Reinjection of the recovered gas into the well or injection of the recovered gas into another well for enhanced oil recovery proposed in §60.5377b(a)(4).
- Flaring the gas such that 95% control efficiency is achieved as proposed in §60.5377b(b).
- An annual reporting requirement focused on periods of venting.

We do not support the requirement to make an infeasibility demonstration and safety and technical certification statements in order to use a flare to reduce these emissions[26]; especially at oil wells that are connected to gas gathering infrastructure and only temporarily flare gas when unable to sell the gas (see also Comment 4.2).
We also note that EPA even uses controlling associated gas with a control device such as a flare as justification for the storage vessel requirements (87 FR 74793) *"…these sites also may be subject to standards for oil well with associated gas and the compliance burden is shared between those affected facilities to ensure emissions from both storage vessels and oil wells with associated gas are reduced by 95 percent."* This statement is evidence of EPA's clear expectations of the use of flares at oil well facilities that may have associated gas, making the need for these additional demonstrations arbitrary.

While we support the concept of other types of beneficial use proposed in §60.5377b(a)(3), we do not support the list of options proposed in §60.5377b(b)(1) (methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas). Each option listed requires specialized equipment, capital investment, and additional energy to implement the technology that would generate emissions, some of which may be greater than flaring the associated gas directly. Furthermore, the cost-benefit of the proposed hierarchy of requirements has not been adequately justified by the EPA. In fact, EPA has not considered the technical feasibility, costs, or benefits from any of these options in the updated Technical Support Document[27].

4.2 The provisions for associated gas at oil wells that primarily recover associated gas to sales, for injection, or used for onsite fuel must be adequately delineated from associated gas from oil wells that do not have adequate or accessible gas gathering infrastructure.

Specifically, the notion that *"recovering associated gas from the separator and routing the recovered gas into a gas gathering flow line or collection system to a sales line"* constitutes a control option as proposed under

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[26] If retained, the infeasibility demonstration that is a prerequisite to control of associated gas must include consideration of commercial availability of alternatives to pipeline injection and of site economics. Consider, for example, the World Bank's "Zero Routine Flaring by 2030," which seeks "to implement economically viable solutions to eliminate [routine] flaring [of associated gas] as soon as possible."

[27] Supplemental TSD Chapter 6 Associated Gas October 2022 / EPA-HQ-OAR-2021-0317-1578_attachment_7.xlsx

§60.5377b(a)(1) is exceptionally problematic since this explains standard business operations for thousands of wells producing a vital energy resource throughout the country. Including this option within the proposal creates tremendous administrative burden in maintaining the records proposed in §60.5420b(c), without generating environmental benefit as the gas is typically being captured to a sales line already. Selling natural gas is part of our business and this sets a uniquely unjustifiable precedent since operators are in the business to sell as much of the produced gas as possible. In the preamble (87 FR 74779), EPA states *"In addition…a significant addition to the proposed rule is the establishment of requirements for situations when associated gas from an oil well that is primarily either routed to a sales line or used for another beneficial purpose is unable to utilize the gas in that manner due to gathering system or other disruptions."* We agree that these wells should have special requirements for the sporadic, short periods of time that gas cannot be recovered, but the current provisions proposed in §60.5377b(a) do not adequately address associated gas that is typically recovered.

For wells where associated gas from the separator is designed and configured to be recovered, we support simplification of the requirements that focus on the short periods of time when gas is not recovered for sale, injection, or reuse. Specifically, we support flaring the gas by using a permanent or temporary control device[28] that achieves 95% efficiency during periods of time when the associated gas is routed to the control device. In this scenario when a well that is configured to route gas to sales or for reinjection can no longer recover the gas for its primary use, the gas should be immediately routed to the flare as soon as practicable. Since EPA has already acknowledged in the preamble (87 FR 74780) that these situations do occur and are outside the control of the well operator, we do not support making technical or safety demonstrations where disruptions or interruptions in the gas gathering infrastructure result in the need to route the associated gas to a control device for temporary periods. For wells that primarily recover gas for reinjection, conducting compressor maintenance may necessitate temporary periods of flaring. This is reasonable given that a facility is designed with a certain configuration for handling the disposition of associated gas and it is unreasonable to expect facilities to design for multiple uses based on emerging technologies before they can resort to flaring; especially during these short intermittent periods.

Any retention of technical demonstrations, for wells that do not primarily recover associated gas, should include economic viability.

4.3 EPA should include a definition for associated gas.

EPA did not include a defintion of associated gas within §60.5430b or §60.5430c, which we do not believe was EPA's intent. Within the preamble[29] EPA uses the following language when describing associated gas. We believe this language with a few additional clarifications would be appropriate to clearly describe associated gas from oil wells for the purposes of NSPS OOOOb and EG OOOOc. The distinctions we provide explicitly determine which separator the requirements proposed in §60.5377b(a) would apply, providing clear transparency for the regulated community.[30]

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[28] A temporary control may be needed in certain situations that an operator may not have planned for or may not have expected. . Allowing both permanent or temporary flare provides flexibility for locations where an existing permanent control device cannot be used or where has not yet been installed.

[29] 87 FR 74778

[30] Without a clear definition, there is uncertainty of what gas EPA seeks to control. For example, some members debate if EPA meant to include flaring from storage vessels. By limiting to the first stage of separation, operators will clearly know what associated gas is applicable.

> *Associated gas means the natural gas which originates at oil wells operated primarily for oil production and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon during the initial stage of separation after the wellhead.*

4.4 Using associated gas as purge or pilot gas for a control device should be considered beneficial use.

Pilot and/or purge gas allow flares and other control devices to operate safely and effectively to reduce emissions. Furthermore, NSPS OOOOb and EG OOOOc require flares and enclosed combustion devices to have a continuously burning pilot flame when the flare is in use. Enclosed combustion devices are also required to maintain a minimum inlet flow rate, which may require supplemental fuel. In other words, pilot and purge gas are part of the fuel requirements for a flare or enclosed combustion device and are not controlled vent streams.

Since the use of associated gas as an onsite fuel source is one of the proposed beneficial use options in §60.5377b(a)(2), we request that EPA clarify that purge or pilot gas for a control device is considered part of onsite fuel use as shown in the following suggested edit to §60.5377b(a)(2):

> *Recover the associated gas from the separator and use the recovered gas as an onsite fuel source, which may include using the recovered associated gas as purge or pilot gas for a control device or flare.*

As an alternative, EPA could clarify that purge or pilot gas for a control device is considered a useful purpose option under §60.5377b(a)(3).

4.5 Special considerations for handling associated gas from wildcat and delineation wells

In our January 31, 2022 comment letter, we asked EPA to allow certain provisions for wildcat or delineation wells in its proposal with respect to the associated gas from oil well provisions. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. In many instances an operator will not know or understand the composition of the gas until after the well is drilled. EPA has acknowledged this fact within the definitions that have been published in §60.5430a and maintained in the proposed §60.5430b & §60.5430c where the terms are defined as:

> *Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.*
>
> *Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.*

In response to our January 31, 2022 comment letter, EPA stated (see 87 FR 74780):

> *"The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for these situations due to lack of specific sufficient information. Therefore, the EPA is interested in additional information on gas compositions of associated gas that would make it both unusable for a beneficial purpose and unable to be flared. The EPA is not only interested in why commenters feel these situations warrant an exemption from the associated gas standards as proposed, but also*

> *what methods are currently in use, or could be used, to minimize methane and VOC emissions in these situations."*

Like provisions within NSPS OOOOa for well completions, EPA should allow special considerations for handling associated gas since these activities are exploratory in nature and are typically not located near existing infrastructure. Wildcat or delineation wells will typically only produce for short period of time after flowback ends in order to complete well testing where the production flow rate is determined along with other parameters such as the gas composition before the well is shut-in or capped, which is regulated based on state protocols.[31] These wells are typically located in remote locations far from any form of permanent infrastructure thereby disallowing any beneficial reuse from a practical and logistical standpoint since the gas composition is not known.

As an example, on the Alaskan North Slope, ice roads must be built to access locations where exploration activities are taking place because roads do not exist, and there is not access/connection to existing oil and gas infrastructure. As we described above, characteristics of associated gas from these wildcat / delineation wells is unknown and therefore it is not wise to use as an onsite fuel source. Currently under NSPS OOOOa and under proposed NSPS OOOOb, the initial well flowback is subject to the well completion operation requirements, which allow for use of a completion combustion device. After the flowback ends, the well undergoes cleanout and a well test (extended flowback) is conducted to determine reservoir characteristics. There will still be open top tanks and a combustion device present; however, this equipment will only be utilized for a very short duration. The compliance requirements for both the provisions in §60.5377b(a) or §60.5412b do not allow for realistic implementation for such unique and short-term operations which are not permanently producing oil from a well.

Since wildcat or delineation wells will typically cease production in well under 180 days[32], a temporary or portable combustion device similar to those used to control emissions from well completions is appropriate to reduce VOC and methane emissions. We therefore request EPA allow any associated gas produced from wildcat or delineation oil wells be routed to a completion combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways). Due to the temporary nature of these activities, the control device compliance requirements should mimic the requirements of control devices utilized for well completions affected facilities, i.e., operated with a reliable continuous pilot flame and no further compliance requirements.

Suggested Redline for inclusion within §60.5377b:

> *For each wildcat or delineation oil well with associated gas at a well affected facility, capture and direct recovered associated gas from the separator to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

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[31] EPA determined well testing "*conducted immediately after well completion, is considered part of the well completion"* for the purposes of reporting emissions under the Greenhouse Gas Reporting Program (see definition of Well Testing Venting and Flaring in §98.238).

[32] We note the initial performance test for enclosed combustion devices not tested by a manufacturer would not be required until within 180 days after initial startup or start of production. Wildcat or delineation wells typically do not produce for this long to warrant compliance with these provisions. Furthermore, duration of well testing flowbacks from wildcat and delineation wells can be limited to 30 days per other agency regulations/guidance, e.g. BLM's NTL-4A guidance (and proposed Waste Prevention rule) generally limits this activity to 30 days, extension beyond 30 days requires additional approval by the agency.

4.6 EPA's Model Plant Analysis Assumptions

Based on preliminary review of EPA's technical support document that was issued in conjunction of the Supplemental Proposal, the associated gas model plant analysis does not include assumptions reflective of actual proposed requirements.

- In our January 31, 2022 letter, we stated *"a more representative cost for installing a flare suitable to control associated gas would be $100,579, based on the average costs EPA uses for analyzing storage vessel controls."*[33]. We also stated, *"that we did not include the costs from EPA's Workbook 'MP1 Plus Monitors.xlsx' as this would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the proposal. If EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA's cost analysis."* In the Supplemental Proposal EPA has proposed additional parametric monitoring but has not included these costs in the analysis.

- The EPA should consider model facilities that have existing control devices but now need to install the correct flow and other parametric monitoring equipment as this would be a type of model plant scenario not evaluated by the EPA.

- None of the beneficial reuse emerging technologies have been included within the model plant analysis. It is unclear how EPA has justified the inclusion of these technologies related to costs, feasibility or environmental benefit/disbenefit.

- EPA includes no costs associated with the technical demonstrations proposed. There are direct costs associated with the engineering certification process, whether companies support in-house engineers or leverage third parties. In previous API comments we have provided to the EPA, we estimated certifications to be $2,000 - $9,000.[34]

- The EPA seems to bias the data selected for baseline emissions to fit their expectation and not based on actual reported data. In section 6.3.1 of the technical support document[35] EPA states,

  > *There were 95 facilities/basins that reported associated gas venting emissions [through GHGRP subpart W data]. For each facility/basin, the number of wells venting is reported, along with the total methane vented from all wells. For each facility/basin, we calculated the average emissions per well. These average well emissions ranged from 0.015 tpy to over 2,400 tpy. Almost 20 percent of the facilities/basins had average well methane emissions less than 0.2 tons per year. Explanations of the specific causes of emissions is not provided in the GHGRP subpart W outputs, but it would be expected that routine venting of associated gas would result in emissions greater than this level. In order to avoid selecting a well associated gas venting level that was unreasonably low, a weighted average well emissions level was calculated, using the total emissions from the facility/basin as the weighting factor. The result is an estimated average*

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[33] EPA-HQ-OAR-2021-0317-0039

[34] EPA-HQ-OAR-2017-0801

[35] EPA-HQ-OAR-2021-0317-1578

> *annual methane emissions level of 344 tpy. Applying the representative composition yields a representative VOC emissions level of 96 tpy.*

Within these statements, EPA acknowledges that there are very low methane emissions generated from wells that only temporary flare associated gas when the primary recovery method is not available (i.e. routing to sale, for injection, or used as onsite fuel). However, the EPA in this proposal has not made the distinction between facilities that temporarily flare versus those that are truly stranded.

5.0 Control Devices, Covers and Closed Vent Systems

API supports EPA's decision to maintain the 95% control efficiency standard for control devices within NSPS OOOOb and EG OOOOc, and we acknowledge EPA's desire to assure proper control device performance. The following recommendations will allow this goal to be achieved more effectively at well sites, centralized production facilities, compressor stations, and natural gas processing plants. Specifically, the proposed control device and cover and closed vent system requirements present technical feasibility, timing, and cost issues. To address these concerns, NSPS OOOOb and EG OOOOc should allow for more cost-effective monitoring alternatives and better alignment between monitoring requirements for manufacturer-tested enclosed combustion devices and other enclosed combustion devices. Comments concerning both control devices and closed vent systems are presented in this section.

5.1 Emissions detected from covers and closed vents system do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

EPA states in the Preamble that when a leak is detected in a cover or a closed vent system during a fugitive emissions survey, alternative screening survey, or by a continuous monitoring system, "*the emissions would be considered a violation of the [no identifiable emissions] standard and thus a deviation*"[36]. The "no identifiable emissions standard" or NIE standard is a design and work practice standard (***emphasis added***).

> *You must **design and operate** the closed vent system with no identifiable emissions as demonstrated by §60.5416b(a) or (b), as applicable.37*

As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. EPA has presented no reason in the Proposal to depart from its historical approach regarding fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in

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[36] 87 FR 74804

[37] §60.5411b(a)(3)

compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed.

A “no identifiable emissions” or “no detectable emissions” standard cannot constitute a numerical emissions limitation since BSER must be achievable, so the standard must be applied as a work-practice standard. Even the most well-designed and operated system will develop a leak due to wear and tear on equipment. A zero emissions standard for cover and closed vent system components is practically unachievable because some leaks will happen in the normal course of operations (e.g., typical fugitive leaks) and some develop due to causes beyond an operator’s control. Consider that if a leak from a rusty bolt on a pipe flange is only subject to the standard LDAR work practice standard, then a leak from a rusty bolt on a cover or closed vent system should also only be subject to the standard work practice standard. There is no reason why a typical fugitive leak should be treated differently simply because it occurs on a cover or closed vent system.

Additionally, a leak may develop due to malfunctions or a foreign object (e.g., sand or dust), both of which are not reasonably within the control of the operator. Such leaks are not caused by inadequate design or improper operation and cannot constitute a violation of the “no identifiable emissions” standard. API recognizes the possibility of improperly operating a cover or closed vent system (e.g., forgetting to close a thief hatch), but EPA should clearly differentiate these types of leaks from those described above. For these reasons, EPA’s application of the standard as a numerical emission limitation is not only unachievable but will also have will have a chilling effect on companies that aim to do voluntary leak surveillance, and disincentivize the use of more sensitive instruments. EPA should encourage and incentivize operators to conduct additional voluntary monitoring without the fear of an automatic violation if a leak is detected from a cover or closed vent system.

Lastly, CAA § 111(h)(2) provides that a work practice standard should be prescribed in lieu of a standard of performance (i.e., numeric emissions limitation) when “a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant.” That is precisely the case with EPA’s proposed NIE standards. The NIE standards do not apply to emissions from the storage vessel or equipment to which the closed vent system is installed. Rather, the proposed NIE standard applies to the closed vent system itself. In this case, it is obvious that there is no “conveyance” through which the regulated pollutants would be emitted or captured. To accomplish such an outcome, the closed vent system to which the NIE standard applies would have to be enclosed within another closed vent system or similar permanent total enclosure in order for the regulated emissions to be captured for subsequent control or venting. Requiring such a system would be inordinately costly, highly impracticable, and likely impossible. This is precisely why LDAR standards have been expressed from the inception of such programs almost exclusively as work practice standards. In short, the NIE standard cannot be effectively construed as a zero-emissions standard, as EPA proposes, because no “conveyance” exists that allows for capture of the regulated emissions and application of such a standard to an emissions point.

5.2 Supply chain delays for acquiring flow meters or other monitoring equipment necessitates the initial compliance period must be extended to at least one (1) year after publication in the Federal Register.

Due to EPA’s proposed designation of the applicability date aligned to the November 2021 proposal (see Comment 12.1), operators may not have the adequate flow and net heating value monitoring technology in place for all sites subject to the provisions proposed in NSPS OOOOb, because these additional monitoring requirements were only contemplated but not specifically proposed in that initial proposal. Since EPA’s proposal for consistent control device monitoring requirements regardless of the affected facility will apply to both NSPS

OOOOb and EG OOOOc, the number of control devices subject to monitoring requirements will increase significantly. The current supply chain delay for acquiring flow meters or similar monitoring equipment is currently approximately 6 to 8 months. This delay within the supply chain is expected to be exacerbated based on both NSPS OOOOb and EG OOOOc implementation over the coming years.

In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk.Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap.

As an alternative, a site shutdown to install control device monitoring equipment will result in emissions from the shutdown and purging of equipment and piping. Shutdowns at midstream compressor stations or gas plants could result in gas venting, gas flaring, or a shut-in at upstream facilities. A shorter compliance period will multiply these disruptions as operators work to comply with NSPS OOOOb.

In the 2012 NSPS rule[38], EPA allowed implementation for storage vessel requirements to be phased-in to accommodate the vast number of affected facilities and the number of control devices that would be needed to be acquired. Other state rules, such as those in Colorado and New Mexico[39], have allowed for an orderly phase-in period for certain requirements. EPA must consider that a similar compliance schedule is warranted in the proposed NSPS OOOOb and EG OOOOc based on similar constraints and concerns for acquiring the appropriate monitoring equipment that has historically been exempt from control devices for storage vessel affected facilities. The current supply chain delays in acquiring equipment and limited resources to install equipment are expected to be exacerbated by the large number of control devices subject to monitoring under NSPS OOOOb or EG OOOOc.

Based on feedback from members, we request the initial compliance period for control device flow and net heating value monitoring requirements be extended from 60 days after final publication in the Federal Register to at least 1 year after publication in the Federal Register to allow operators time to order and install the necessary meters assuming that the applicability is based on the December 6, 2022 and other our comments concerning reconstruction and modification are addressed. Additional time, at least another year, would be required if the rules are finalized as proposed. Specifically, compliance with the flow and net heating value monitoring requirements at §60.5417b(d)(1)(vii)(A), §60.5417b(d)(1)(viii)(B), and §60.5417b(d)(1)(viii)(D) along with related operational requirements must be extended to allow operators adequate time to procure and install the necessary monitoring equipment where appropriate as various new equipment is installed, or other equipment is modified or reconstructed.

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[38] See EPA's response at 77 FR 49525-49526.

[39] 20.2.50.122.B(3) NMAC and 20.2.50.123.B(1) NMAC

5.3 With the increased number of control devices subject to flow monitoring requirements, the accuracy requirement for flow meters should be ±10% of maximum expected flow.

For manufacturer-tested enclosed combustion devices, EPA is maintaining the current flow monitoring accuracy requirement of ±2% or better[40]. Historically, this requirement only applied to control devices for wet seal centrifugal compressors and was not required for control devices used to reduce emissions for other affected facilities under NSPS OOOO or NSPS OOOOa. Vent gases from centrifugal compressors have relatively stable flow rates while vent gas from storage vessels is intermittent, low pressure, low velocity / flow, and more difficult to measure.

Since EPA is proposing consistent control device monitoring requirements regardless of the affected facility controlled for both NSPS OOOOb and EG OOOOc, the number of control devices subject to flow monitoring requirements will increase significantly under NSPS OOOOb and EG OOOOc.

The ±2% accuracy requirement may not be technically feasible for most commercially available meters nor cost-effective for control devices on every affected facility at well sites, central production facilities, compressor stations, and natural gas processing plants. As mentioned in Comment 5.2, the availability and cost of meters are negatively affected by supply chain constraints and limited resources to install them. API has previously commented[41] on the challenges with flow monitoring at upstream facilities. This level of accuracy is also more stringent than the ±5% accuracy requirement for flare vent gas flow rates at velocities above 1 feet per second under Maximum Achievable Control technology (MACT) standards finalized under 40 CFR 63 SubpartCC (RMACT)[42].

Two types of commercially available flow meters that are commonly used are thermal dispersion meters or ultrasonic meters. Ultrasonic flow meters are the only identifiable meter that can achieve the ±2% accuracy, but this accuracy may decrease under low-flow or low-pressure conditions. While these meters are technically feasible to meet the proposed accuracy requirement, they may not be economically reasonable with an estimated cost of $20,000 to $30,000 each. In EPA's cost analysis for storage vessels controls[43], the cost of a flare with monitoring equipment was estimated but was not used in the subsequent BSER analysis for new or existing sites. Therefore, EPA did not fully consider the cost-effectiveness of the proposed monitoring requirements for control devices. Thermal dispersion flow meters are less expensive but may not meet the accuracy requirement with a typical accuracy of ±5% or better at high flows (accuracy decreases at pressures less than 25 psig). The lower pressure and variable flow rates from certain affected facilities such as storage vessels also make the accuracy requirement difficult to meet. If a control device is used for controlling atmospheric storage tanks only, it will be operating at less than 25 psig and so even a ±5% accuracy may be difficult to achieve; therefore, the flow meter accuracy requirement must consider this likely scenario. In colder conditions, like those experienced in North Dakota and other states, the liquid drop out caused by condensation can also reduce the accuracy of flow meters and make an accuracy of ±2% technically infeasible. Therefore, API proposes that the accuracy for control device inlet flow rate be increased to ±10% of maximum expected flow.

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[40] §60.5417(d)(1)(viii)(A) and §60.5417a(d)(1)(viii)(A)

[41] API's December 4, 2015, comments on the proposed Subpart OOOOa and January 31, 2022, comments on the proposed Subparts OOOOb and OOOOc.

[42] 40 CFR 63 Subpart CC Table 13

[43] EPA-HQ-OAR-2021-0317-0039, "StTanks_Control_Costs_v5.1.xlsx" and "EPA_Flares_Calc_Sheet_MP1plusmonitors.xlsx"

5.4 Flow monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices.

Manufacturer-tested enclosed combustion devices function similarly to other enclosed combustion devices with the only difference being the party responsible for stack testing; therefore, the proposed flow monitoring requirements should be consistent regardless of whether the device is tested by the manufacturer or owner/ operator. In comparing the proposed flow monitoring requirements for manufacturer-tested enclosed combustion devices at §60.5417b(d)(1)(vii)(A) and other enclosed combustion devices at §60.5417b(d)(1)(viii)(D), the following inconsistencies were noted and should be addressed.

- **No accuracy requirement is specified for other enclosed combustion devices.** As discussed above, the accuracy requirement for flow rate monitoring should be ±5% for both manufacturer-tested and other enclosed combustion devices.
- **Manufacturer-tested devices appear to be limited to flow meters while other enclosed combustion devices may use other parameter monitoring systems.** Other parameter monitoring systems combined with engineering calculations should also be an option for flow monitoring on manufacturer-tested devices especially considering the potential challenges in obtaining and installing a flow meter in a timely fashion. Other parameter monitoring systems are also needed in situations where flow monitoring is infeasible (e.g., low flow scenarios). These other parameter monitoring systems would be more stringent than MACT HH, which allows GRI-GLYCalc™ or other process simulation to calculate inlet flow rate for manufacturer-tested control devices[44].
- **Manufacturer-tested devices do not have an option to exempt the device from flow monitoring.** For enclosed combustion devices not tested by the manufacturer, maximum inlet flow rate monitoring is not required if a demonstration can be made using engineering calculations, and minimum inlet flow rate monitoring is not required if a backpressure valve is properly installed and operated. These alternative compliance options for flow rate monitoring should also be available to manufacturer-tested devices.
- **EPA should clarify that a backpressure preventer is a backpressure valve.** Since backpressure preventer is an unclear term, EPA should use the term "backpressure valve" instead.
- **Additional examples of other parameter monitoring systems should be added to the regulatory text.** To clarify and elaborate on the variety of other parameter monitoring systems that could be used in lieu of a flow meter, EPA should consider adding inlet pressure and line size as additional examples in the regulatory text.

Based on these items, API offers the following recommended redline of flow monitoring requirements for manufacturer-tested control devices in §60.5417b(d)(1)(vii)(A):

> *Except as noted in paragraphs (d)(1)(vii)(A)(1) through (4) of this section, ~~T~~the continuous parameter monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ~~±2~~ ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The flow rate at the inlet to the combustion device*

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[44] §63.773(d)(3)(i)(H)(*1*)

must be equal to or greater than the minimum flow rate and equal to or less than the maximum flow rate determined by the manufacturer.

(1) *If you can demonstrate, based on the maximum potential pressure of units manifolded to the control device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the control device cannot cause the maximum inlet flow rate determined by the manufacturer to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.*

(2) *If you install and operate a backpressure valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.*

(3) *Control devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

(4) *Pressure-assisted flares control devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

API also offers the following recommended redline of flow monitoring requirements for control devices not tested by the manufacturer in §60.5417b(d)(1)(viii)(D):

Except as noted in paragraphs (d)(1)(viii)(D)(1) through (4) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustor or flare. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement.

(1) *If you can demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustor cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section or the flare tip velocity limit in §60.18 to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.*

(2) *If you install and operate a backpressure ~~preventer~~ valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.*

(3) *Flares that are exempt from maximum inlet gas flow monitoring and enclosed combustion devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

(4) *Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

Given the small size, dispersed nature, and large number of units affected by this rule, these changes would appropriately reduce the burden of compliance while still providing for compliance demonstration and monitoring.

5.5 EPA must provide the minimum inlet flow rate for current manufacturer-tested control devices no later than publication of the final rule so that owners and operators are able to achieve compliance.

In the preamble[45], EPA states that previously tested manufacturer control devices "*would not need to perform new performance tests*" and "*[t]he zero-level at which the combustion control device was tested will be extracted from the previously submitted performance test report and added to the information on the EPA's website*". This minimum flow rate information must be added to the EPA's website[46] no later than publication of the final rule since owners and operators cannot extract the information themselves as the underlying test reports are not currently available on the website. This minimum flow rate information may also not be easily obtained from the manufacturer directly. EPA must provide this minimum flow rate information no later than publication of the final rule so that owners and operators are able to take any necessary action (e.g., purchase of a different control device or operational changes) to achieve compliance. If the minimum flow information is not provided by the publication of the final rule, EPA should consider implementing a longer initial compliance period (see Comment 5.2).

5.6 EPA should allow the use of alternative technologies within the proposed monitoring requirements.

Given the increasing number of control devices subject to proposed monitoring requirements, EPA should allow the use of alternative technologies to meet the monitoring requirements for visible emissions, continuous pilot flame, and minimum net heating value. Well sites, centralized production facilities, and compressors do not have the same utilities and instrumentation resources as refineries, so alternative technologies would provide more cost-effective monitoring of control device performance.

5.6.1 A smoking check should be the primary monitoring method for visible emissions from flares and enclosed combustion devices.

Thousands of flares and enclosed combustion devices will be subject to proposed monthly Method 22 observations and associated recordkeeping. Each of these observations requires 15 minutes and detailed records to document that the observation was conducted according to Method 22. In total, these observations will add up to hundreds to thousands of hours each month and thousands to tens of thousands of hours per year with no added environmental benefit if the device is operating properly. Compliance can more easily be monitored using a monthly smoking check with a record documenting the time of the observation and whether the control device is observed to be smoking. If the device is observed to be smoking, then operator would be able to either 1) assume the device failed the visible emissions requirement and immediately take corrective actions or 2) conduct the 15-minute Method 22 observation to determine whether the device meets the visible emissions requirement. A monthly smoking check could reduce the time required to monitor the device by more than 90%, and this saved

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[45] 87 FR 74796

[46] https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers

time could be used for other tasks with greater environmental benefit (e.g., conducting a required AVO and/or OGI survey while at the site).

5.6.2 Video camera systems should be allowed as an alternative to Method 22.

Since some sites are already equipped with video camera systems, EPA should also allow video cameras as an alternative method to conduct the required monthly smoking check or Method 22 visible emission observations for enclosed combustion devices and flares. Video camera systems are allowed as an alternative to Method 9 observation under Broadly Applicable Approved Alternative Test Method ALT-82[47]. Although these video camera systems have similar supply challenges to other monitoring equipment (see Comment 5.2), they should be an allowed monitoring alternative. To be consistent with the smoking check or Method 22 requirement, the camera would be used to remotely conduct a smoking check and/or 15-minute observation for visible emissions from the control device every month. Owners or operators would keep a record of this remote visible emission observation with similar information required for in-person smoking check or Method 22 observation. Artificial intelligence and machine learning should be allowed to continuously screen the video feed for smoke detection and if smoke is detected, alert the operator that a Method 22 follow-up is required. Making the requirements for video camera systems more stringent than the proposed monthly Method 22 observation would disincentive the use of this alternative. Recordkeeping and reporting of additional video records could pose potential security risks and data storage concerns.

5.6.3 An automatic ignition system with a flame monitoring device should be allowed as an alternative to a continuous pilot flame.

A continuous pilot flame requires propane or other supplemental fuel at sites without fuel gas. For sites with sour gas, a continuous pilot flame requires either using the sour gas as the pilot or bringing in propane or other supplemental fuel to supply the pilot. Burning propane or other supplemental fuel is costly and generates additional emissions when no vent streams are sent to the control device. Similarly, burning sour gas generates additional emissions including SO_2 and potentially uncombusted H_2S. Some state rules, such as New Mexico[48] and Texas[49], allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. Therefore, API proposes that an automatic ignition system with a flame monitoring device be allowed as an alternative to a continuous pilot flame.

5.6.4 The minimum net heating value demonstration should be simplified.

EPA should provide flexibility to operators by simplifying its proposed minimum net heating value demonstration alternative to continuous net heating value monitoring. Both the proposed continuous net heating value monitoring and demonstration alternative seem excessive considering that the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirements. These vent streams consist of mostly hydrocarbons, and the simplest hydrocarbon (methane) has a net heating value of approximately 900 Btu/scf, which is 450%, 300%, or 112% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf depending on the type of control device.

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[47] https://www.epa.gov/sites/default/files/2020-08/documents/alt082.pdf

[48] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(b) NMAC

[49] 30 TAC §106.492(1)(B)

The proposed minimum net heating value demonstration requires continuous monitoring over 10 days or a minimum of 200 hourly samples of inlet gas to the flare or enclosed combustion device. EPA's justification for such an extensive sampling campaign is *"to provide a large sampling set by which to assess the variability of the vent gas sent to the combustion device and to adequately characterize the tails of the distribution."*[50] EPA did not provide additional detail as to why it expects the distribution of vent gas composition to vary enough to potentially be below the required minimum net heating value. Such a large sampling set is unnecessary when the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirement.

Vent streams from oil well with associated gas, centrifugal compressor, and pneumatic controller in Alaska affected facilities are typically comparable to sales gas or natural gas. In AP-42, natural gas is listed as having a gross heating value of 1,020 Btu/scf (Section 1.4) or 1,050 Btu/scf (Appendix A). The "2011 Gas Composition Memorandum"[51] used in EPA's TSD also suggests net heating values well above the required minimum. Gas composition typically does not change unless certain actions occur at the site, such as adding a new well or refracturing an existing well. Even though the gas composition will typically change with new or modified well streams, composition remains well above the required minimum net heating value.

Vent streams from storage vessel affected facilities consist of more large hydrocarbons than sales gas and have a typical net heating value of 2,000 Btu/scf or more, which is 1,000%, 667%, or 250% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf, respectively. The addition of air from an open thief hatch could drop the heating value of tank vapors below the required minimum net heating value, but the proper operation of thief hatches and other openings are already addressed in the proposed cover requirements.

Vent streams from affected facilities that could potentially be below the minimum heating value requirement include compressors in acid gas service or those at Enhanced Oil Recovery (EOR) facilities. Both situations could have high carbon dioxide (CO_2) content which would lower the net heating value, so operators typically add assist gas or another vent stream with sufficient heating value to facilitate proper control device operation. In these limited situations, API proposes that flow monitoring of the assist gas and vent streams should be allowed as an alternative to the continuous monitoring of net heating value in these limited situations.

Since the vent streams from affected facilities are expected to have sufficient heating value, both the proposed continuous net heating value monitoring and demonstration alternative are economically unreasonable. Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000. These monitors may also experience operational issues with entrained liquids in the vent gas stream especially in colder climates and seasons. For the minimum net heating value demonstration alternative, the cost is expected to be $250,000 or more per demonstration. The cost of a vendor-conducted 10-day continuous monitoring campaign is estimated at a minimum of $250,000 to $275,000 while the cost of 200 hourly samples is estimated at a total of $300,000 to $400,000 with an average cost per sample of $1,500 to $2,000 including shipping and analysis.

Since EPA's proposed minimum net heating value demonstration is too onerous and costly, API proposes the following to provide operators the necessary flexibility to comply with net heating value requirements:

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[50] 87 FR 74795

[51] EPA-HQ-OAR-2010-0505-0084

- The 10-day demonstration be simplified to a single sample including the use of an appropriate, representative sample or an initial flare compliance assessment with §60.18 using Method 18 of Appendix A. If a representative sample is used, the operator must document why the sample is characteristic of the vent stream composition. If the sample or §60.18 assessment demonstrates that the net heating value is at least 150% of the applicable minimum value (i.e., net heating value of the sample is at least 300, 450, or 1,200 Btu/scf, as applicable), net heating value monitoring would not be required. After the initial demonstration, continuous compliance would be demonstrated through subsequent samples once every 3 years. If the initial or subsequent sample is below 150% of the applicable minimum net heating value, the operator would be required to conduct more extensive sampling as proposed below or install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- If an initial or subsequent sample does not meet 150% of the minimum net heating value, operators should have the option to conduct a more extensive sampling event with a lower threshold. API proposes that this more extensive demonstration consist of a minimum of 2 hourly samples or 2 hours of continuous monitoring per day for 7 days for a total of 14 samples. The same number of samples is required for a comparable net heating value demonstration under RMACT[52]. Net heating value monitoring would not be required if all 14 hourly averages or samples are above 120% of the applicable minimum net heating value requirement. After the initial 7-day demonstration, continuous compliance would be demonstrated through a grab sample taken once every 3 years. If the initial or subsequent samples are below 120% of the applicable minimum net heating value, the operator would be required to install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- As with the proposed flow monitoring requirements, net heating value monitoring or demonstration alternative should not be required if operators demonstrate that the net heating value is never expected to below the minimum required value using applicable engineering calculations including process simulation software. This alternative would be similar to MACT HH, which allows GRI-GLYCalc™ or other process simulation software to be used to estimate benzene or BTEX emissions from a glycol dehydration unit[53]. Continuous compliance would be demonstrated through a grab sample taken once every 3 years to verify that the minimum net heating value is being met.

5.7 Minimum operating temperature and associated monitoring requirements should be revised.

NSPS OOOOb proposes a minimum operating temperature of 760 °C and temperature monitoring for enclosed combustion devices that demonstrate that combustion temperature is an indicator of performance during initial performance testing. Other enclosed combustion devices (i.e., those for which combustion temperature is not demonstrated to be an indicator of performance) would be subject to net heating value monitoring requirements. Given the increased number of control devices subject to NSPS OOOOb and EG OOOOc, EPA should revise the minimum operating temperature and associated monitoring requirements in the following ways:

- **Allow operators the flexibility to comply with either temperature or net heating value requirements for enclosed combustion devices that demonstrate that combustion temperature is an indicator of**

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[52] §63.670(j)(6)

[53] §63.772(b)(2)(i)

performance. Some enclosed combustion devices, such as thermal oxidizers, are designed with a minimum operating temperature while others are not. Even if a device can demonstrate that temperature is an indicator of performance during testing, maintaining a minimum operating temperature during actual operation may be challenging and require additional supplemental fuel due to the low or intermittent flow of the vent streams. As proposed, a minimum operating temperature with associated monitoring is the only option for enclosed combustion devices that demonstrate combustion temperature is an indicator of performance. For those enclosed combustion devices, operators should be able to comply with net heating value requirements as an alternative.

- **Allow the minimum operating temperature to be established by performance testing.** Rather than a fixed minimum operating temperature, EPA should allow operators the flexibility to comply with a default minimum operating temperature of 760 °C or the value established by the most recent performance testing. The enclosed combustion device may be able to demonstrate compliance at an operating temperature below 760 °C. Also, additional supplemental fuel may be required to keep the device at a minimum operating temperature of 760 °C when it could achieve a 95% control efficiency at a lower temperature. Operators should be allowed to conduct performance testing as needed to establish a new minimum operating temperature.

- **Allow a minimum operating temperature and temperature monitoring for manufacturer-tested devices.** As proposed, the minimum operating temperature and associated monitoring applies only to enclosed combustion devices not tested by the manufacturer. Like operators, manufacturers should be allowed to demonstrate that combustion temperature is an indicator of performance through performance testing and allow temperature monitoring as an option for demonstrating compliance. Operation and monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices like our recommendation on flow monitoring in Comment 5.4.

5.8 Manufacturer-tested enclosed combustion devices should continue to be exempt from periodic performance testing.

Under NSPS OOOO and MACT HH, manufacturer-tested control devices are exempt from periodic performance testing. Under NSPS OOOOa, manufacturer-tested control devices on centrifugal compressors are exempt from periodic performance testing if the device has continuous flow monitoring. NSPS OOOOb proposes that manufacturer-tested control devices be subject to both periodic performance testing and continuous flow monitoring. These requirements appear contrary to both the technical challenges in conducting performance tests in the field reiterated by EPA and the agency's intent stated in the preamble (***emphasis added***)[54],

> *''[w]e believe that testing units that are not configured with a distinct combustion chamber* ***present several technical issues that are more optimally addressed through manufacturer testing****, and once these units are installed at a facility, through* ***periodic inspection and maintenance*** *in accordance with manufacturers' recommendations.*
>
> *[Text omitted for brevity.]*

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[54] 87 FR 74794

> *For these reasons, we believe the manufacturers' test is appropriate for these control devices with* ***ongoing performance ensured by periodic inspection and maintenance****. ["] (76 FR 52785; August 23, 2011).*

Given EPA's previous rationale for manufacturer testing, the monitoring requirements proposed under NSPS OOOOb, and the increased number of control devices subject to these monitoring requirements, API recommends that manufacturer-tested control devices continue to be exempt from periodic performance testing.

5.9 Enclosed combustion devices subject to minimum operating temperature and temperature monitoring should also be exempt from periodic performance testing.

Under MACT HH, combustion devices are exempt from periodic performance testing if the device demonstrates during initial performance testing that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 °C. NSPS OOOO requirements[55] changed this exemption to devices that meet the outlet TOC performance level and that establish a correlation between firebox or combustion chamber temperature and the TOC performance level. NSPS OOOOa[56] adds a temperature monitoring requirement to the NSPS OOOO exemption for control devices on centrifugal compressors.

Like manufacturer-tested devices, NSPS OOOOb proposes to remove this exemption from periodic performance testing. As such, enclosed combustion devices that demonstrate during initial performance testing that combustion zone temperature is an indicator of destruction efficiency are subject to a minimum operating temperature, periodic performance testing, and temperature monitoring. Given the consistent monitoring requirements proposed under NSPS OOOOb and the increased number of control devices subject to these monitoring requirements, API proposes that enclosed combustion devices for which temperature is correlated with destruction efficiency be exempt from periodic performance testing.

To clarify the requested exemptions from periodic performance testing, API offers the following suggested redline of §60.5413b(b)(4)(ii):

> *You must conduct periodic performance tests for all control devices required to conduct initial performance tests, except ~~for a control device whose model is tested under, and meets the criteria of paragraph (d)~~ as specified in paragraphs (b)(4)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(4)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420b(b)(12).*
>
> *(A) A control device whose model is tested under and meets the criteria of paragraph (d) of this section.*
>
> *(B) A combustion control device demonstrating during the performance test under paragraph (b) of this section that combustion zone temperature is an indicator of destruction*

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[55] §60.5413(b)(5)(ii)(B)

[56] §60.5413a(b)(5)(ii)(B)

efficiency and operates at a minimum temperature of 760 °Celsius or the minimum temperature established during the most recent performance test.

5.10 The continuous monitoring option for organic compound concentration in the control device exhaust may not be technically feasible or economically reasonable. This monitoring option is also meaningless without the corresponding outlet concentration performance standard.

As an alternative to continuous flow monitoring and other similar monitoring requirements, EPA has retained the existing option under NSPS OOOO and OOOOa to use a continuous monitor for organic compound monitoring in the control device exhaust. However, such monitoring may not be a technically feasible or economically reasonable alternative to the other continuous monitoring requirements.

Furthermore, this monitoring option does not make sense since the previous TOC outlet concentration performance standard was not proposed for NSPS OOOOb and EG OOOOc. EPA should clarify if the removal of this alternate performance standard was intentional and how operators should handle compliance for existing control devices that are complying with the TOC concentration standard under NSPS OOOO or OOOOa.

5.11 Technical clarifications for proposed control device requirements.

5.11.1 EPA should clarify requirements for regenerative carbon adsorption systems that use a regenerant other than steam.

For some existing regenerative carbon adsorption systems, residue gas or another regenerant is used instead of steam since the sites typically do not have access to a steam system like a chemical plant or refinery. In the natural gas production and processing industry, natural gas (mostly methane) with a set of heat exchange systems is used to regenerate the carbon beds in place of steam. These systems can be used when there is potential to have air enter the system. A carbon bed does not have a direct fire source which can help limit the potential for a fire in the system. The regeneration cycle is infrequent for these systems. While the proposed requirements for regenerative carbon adsorption systems are unchanged from NSPS OOOOa, EG OOOOc will subject existing sources and control devices to methane standards, and API would like to confirm these regeneration cycles would not be part of the control requirements under this rule. Operators should not be forced to change the operation of their existing control device provided they meet the applicable requirements. Forcing sites to switch to steam regenerant may be technically infeasible or economically unreasonable.

5.11.2 EPA should clarify the proposed requirement language around the presence of pilot flames.

The proposed requirements for control device pilot flames use the following three phrases, each of which could suggest a different meaning:

- A **“continuous burning pilot flame”** means a pilot flame is required at all times regardless of whether the site is operating or vent gas is sent to the control device.

- A **"pilot flame present at all times of operation"** could mean either a pilot flame is required at all times the site is operating or only for those times when the control device is operating (i.e., vent gas is sent to the control device)

- **"Pilot flame while emissions are routed to the control device"** means a pilot flame is required only when vent gas is sent to the device (in other words, at all times of control device operation).

A pilot flame should only be required when emissions are routed to the control device since loss of the pilot flame would result in additional emissions only when vent gas is sent to the device. This clarification would allow for the use of automatic ignition systems (see Comment 5.6.3). This clarification would also be consistent with the compliance requirement found at §60.5412b(b)(1):

> *You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*

API offers the following redlines that clarify a pilot flame should be required only when emissions are routed to the control device like some state rules including New Mexico[57]:

> *§60.5412b(a)(1)(vii): You must install and operate a continuous burning pilot flame or automatic ignition system.*
>
> *§60.5412b(a)(3)(iv): You must install and operate a continuous burning pilot flame or automatic ignition system.*
>
> *§60.5413b(e)(2): A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*
>
> *§60.5415b(f)(1)(vii)(A)(1): A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(d)(1)(i): For an enclosed combustion control device that demonstrates during the performance test conducted under §60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You also must comply with the requirements of paragraphs (d)(1)(viii)(D) and (E) of this section, and you must install a monitoring device that continuously (i.e., at least once every five minutes) indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(d)(1)(vii)(B): A monitoring device that continuously, at least once every five minutes, indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.*

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[57] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(c) NMAC

> *§60.5417b(d)(1)(viii)(A): Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times while emissions from affected facilities are routed to the control device. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.*
>
> *§60.5417b(g)(1): A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in §60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot flame or combustion flame present for any time period while emissions from affected facilities are routed to the control device.*
>
> *§60.5417b(g)(6)(iii): There is no indication of the presence of a pilot flame or combustion flame for any 5-minute time period while emissions from affected facilities are routed to the control device.*
>
> *§60.5420b(c)(11)(i)(F)(1): Records that the pilot flame or combustion flame is present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.*

5.11.3 EPA should clarify which elements of the control device monitoring plan apply to heat sensing monitoring devices that indicate the presence of a pilot flame.

The proposed control device monitoring plan requirement includes the following exemption: "…*Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements of this section.*"[58] However, one of the listed monitoring plan elements uses a thermocouple as an example. This example is confusing since thermocouples could be used as a heat sensing monitoring device for a pilot flame, or as a temperature monitoring device. In the former case, the exemption would apply but not in the latter. EPA should clarify which elements of the monitoring plan apply to heat sensing devices.

Therefore, API recommends the following redline for §60.5417b(c)(2)(ii):

> *Sampling interface ~~(e.g., thermocouple)~~ location such that the monitoring system will provide representative measurements.*

Alternatively, EPA could propose a different example for sampling interface.

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[58] §60.5417b(c)(2)

5.11.4 EPA should clarify that control devices are not considered fugitive emissions components and how to address emissions from control devices detected during fugitive emissions monitoring.

While EPA recognizes that "control devices should not be treated as fugitive emissions components"[59], EPA adds confusion by trying to address emissions "caused by a failure of a control device subject to §60.5413b" under the alternative periodic screening requirements. API believes that this requirement is intended to address improper control device operation such as an unlit flare when vent gas is routed to it and recognizes that alternative periodic screenings can be an effective tool at identifying such issues. However, such emissions are not fugitive emissions and would not necessarily be part of the follow-up ground-based monitoring survey of fugitive emissions components or inspections of the cover and closed vent system. Since control devices are required to meet a 95% control efficiency, they will always have the potential for uncombusted emissions that could be detected by OGI or alternative technology. Unclear or inappropriate requirements related to detected emissions from control devices may be a disincentive for the use of alternative leak detection technologies. Therefore, EPA needs to reconsider how to better address emissions from control devices that could be detected during fugitive monitoring surveys. Refer to Comment 3.3.2 and Comment 3.4.6 for API's recommendations concerning follow-up action for alternative technologies.

5.12 Idle control devices at a site should be exempt from performance testing and monitoring requirements.

The proposed NSPS OOOOb and EG OOOOc requirements are unclear on whether idle control devices at a site are subject to performance testing and monitoring requirements. Some state rules, such as Colorado, require control devices be installed based on the potential maximum throughput of a site. For a site, the control devices may be installed and operated in series using pressure-activated valves, meaning that vent gas is sent to the first device until it reaches capacity before the excess vent gas is sent to the second device and so on. In actual operation, sites may never achieve the potential maximum throughput and associated emissions rates, so control devices toward the end of the control system are available but always idle. But even if activated, they would not be needed for purposes of complying with NSPS OOOOb or EG OOOOc.

One potential reading of the proposed NSPS OOOOb and EG OOOOc requirements is that such idle control devices are subject to initial and periodic performance testing and monitoring requirements especially if they are manifolded together. Conducting performance tests on idle control devices could increase in emissions since additional gas would need to be sent to the control devices for the purposes of testing or additional temporary piping installed to route vent gas to the idle control device. Furthermore, a failed performance test on an idle control device would force operators to repair, retrofit, or replace the device, increasing compliance costs with no environmental benefit because the idle device is not expected to be required for compliance. EPA recognized the environmental and cost disbenefit of testing idle emission sources in the federal standards for engines found in NSPS JJJJ[60] and MACT ZZZZ[61]. Similarly, installation of monitoring equipment on idle control devices increases costs with no environmental benefit.

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[59] 87 FR 74724

[60] §60.4244(b)

[61] §63.6620(b)

To clarify that idle control devices are exempt from performance testing and monitoring requirements, API offers the following redlines:

> *§60.5400b(a): General standards. You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas / vapor or light liquid service, and connector in gas / vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.*
>
> *§60.5401b(a): General standards. You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.*
>
> *§60.5412b: You must meet the requirements of paragraphs (a) and (b) of this section for each control device ~~used to comply~~ operated for the purpose of complying with the emissions standards for your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.*
>
> *§60.5412b(a): Each control device ~~used to meet~~ operated for the purpose of complying with the emissions reduction standard in §60.5377b(b) for your well affected facility, §60.5380b(a)(1) for your centrifugal compressor affected facility; §60.5395b(a)(2) for your storage vessel affected facility; §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska; or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (a)(3) of this section. As an alternative to paragraphs (a)(1) through (a)(3) of this section, you may install a control device model tested under*

> *§60.5413b(d), which meets the criteria in §60.5413b(d)(11) and which meets the initial and continuous compliance requirements in §60.5413b(e).*
>
> *§60.5412b(b)(1): You must operate each control device ~~used to comply~~ operated for the purpose of complying with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*
>
> *§60.5417b: You must meet the requirements of this section to demonstrate continuous compliance for each control device ~~used to meet~~ operated for the purpose of complying with emission standards for your well, centrifugal compressor, pneumatic controller, storage vessel, and process unit equipment affected facilities.*
>
> *§60.5417b(a): For each control device ~~used to comply~~ operated for the purpose of complying with the emission reduction standard in §60.5377b(b) for well affected facilities, §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section.*

5.13 The monitoring plan for control devices does not need to be site-specific.

EPA is proposing that each control device have a site-specific monitoring plan to address the monitoring system design, data collection, and quality assurance / quality control elements. Operators may install the same control device and associated monitoring system across sites in one or more company-defined areas. Similar to the fugitive monitoring plan requirement, EPA should allow monitoring plans for control devices to be based on a company-defined area or a company-wide plan for a specific make and model of control device. Like the fugitive monitoring techniques, control device monitoring is based on the type of control device and monitoring system rather than the site itself. Requiring practically identical site-specific monitoring plans for the large number of control devices increases the administrative burden for operators with no environmental benefit.

5.14 The first repair attempt timeline for covers and closed vent systems may be impractical for certain locations.

While EPA has retained the existing NSPS OOOOa requirements[62] for a first repair attempt on leaks detected from covers or closed vent systems, the 5-day timeline will apply to significantly more sites under NSPS OOOOb and EG OOOOc than NSPS OOOO and OOOOa. This requirement may be impractical for some sites that have access limitations such as those on leased farmland. While API recognizes the historic importance and priority of repairing leaks on covers and closed vent systems, a longer timeline, such as 15 or 30 days, may be more pragmatic since the number of regulated covers and closed vent systems will increase significantly under NSPS OOOOb and EG OOOOc requirements. A different first repair attempt timeline could have the added benefit of

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[62] §60.5416a(b)(9) and §60.5416a(c)(4)

making repair timelines consistent between fugitive emissions components and covers and closed vent systems, thus streamlining compliance for operators.

6.0 Storage Vessels

API supports EPA's proposed 6 tpy VOC and 20 tpy methane thresholds for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. We also support EPA's retention of the current alternate control standard to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC and 14 tpy methane. With some technical clarification concerning location, API agrees with EPA's proposed definition for a tank battery.

However, API has concerns regarding EPA's proposed criteria for legally and practically enforceable limits, the proposed definition of modification, and some of the proposed operational requirements. These items are detailed in the following section.

6.1 EPA's proposed criteria for legally and practicably enforceable limits have legal implications beyond this rulemaking and pose permitting challenges.

EPA's proposed requirements for legally and practicably enforceable limits also have legal implications beyond this rulemaking, and these restrictions violate the concept of cooperative federalism. EPA's proposed revisions are wholly inconsistent with EPA's reliance on states to administer the Clean Air Act with regard to Title V and PSD. That is, EPA allows states to establish emission limits on sites that keep sites below Title V and PSD permitting thresholds. EPA should continue to defer to states to determine the appropriate level of monitoring, recordkeeping, and reporting requirements to include in permits rather than imposing a list of strict criteria. This has long been an effective approach to reduce recordkeeping burden while reducing potential emissions.

Just as important as the legal implications discussed in Comment 12.10, the proposed criteria for legally and practicably enforceable limits provide no additional benefit and pose several permitting challenges. Existing permits and associated state programs and rules likely do not meet all the required criteria since EPA has historically deferred to the states on the sufficient monitoring, recordkeeping, and reporting requirements to include in the various levels of permits. For example, permits have proposed annual or rolling 12-month limits on emissions and production since the tank PTE thresholds and NSR permitting thresholds are based on annual emissions. EPA should clarify that such annual limits meet the proposed 30-day averaging time for production limits especially since facilities are typically permitted for a worst-case scenario. Another criterion likely not in existing permits is "*periodic reporting that demonstrates continuous compliance*". Historically, periodic reporting has applied to major sources under Title V and affected facilities regulated under a NSPS or National Emission Standards for Hazardous Air Pollutants (NESHAP), which is a small fraction of the sites that will be regulated under NSPS OOOOb and EG OOOOc. Monitoring, recordkeeping, and reporting requirements in a permit should be tailored to align with the level of authorization with minor sources having less requirements than major sources. For streamlined permitting mechanisms, such as Permits by Rule in Texas, the state agency would have to engage in rulemaking before operators could rely on such permits for determining storage vessel and tank battery PTE. Such rulemaking could take months to years, meaning that operators cannot rely on legally and practicably enforceable limits until those rule updates are finalized and effective.

The second permitting challenge is the methane emissions threshold. For permitting, methane is typically regulated as a greenhouse gas for major sources under the PSD program. States may not be able to permit a methane limit under their minor NSR programs. As such, EPA should clarify that a methane emission limit is not required to be explicitly listed in the permit provided the control device and/or production limits are included that would limit the PTE from a storage vessel or tank battery to less than 20 tpy of methane. Another approach is to allow a VOC limit of less than 6 tpy to serve as a surrogate for the methane emission limit. A potential consequence of requiring an explicit methane emission limit is that existing tanks may have a permit that does not make them an affected facility under NSPS OOOO or NSPS OOOOa but will not be able to obtain an updated permit for the purposes of EG OOOOc applicability.

Assuming operators can obtain permits that meet the proposed legally and practicably enforceable criteria, the permitting effort for the hundreds of thousands of existing storage vessel designated facilities potentially subject to EG OOOOc will take years and be an administrative burden on operators and the state permitting authorities with no environmental benefit. One member has estimated that it will take ten (10) years to obtain updated permits at the current preparation and agency review timelines. This estimated effort will likely take longer as other operators also seek to update permits at the same time. Given the potential enormous re-permitting burden for existing storage vessels/tank batteries, EPA should allow operators to rely on VOC limits as a surrogate for methane in existing permits that have previously been understood to be legally and practicably enforceable.

Overall, EPA's proposed requirements for legally and practicably enforceable limits have broad legal implications and impose real permitting challenges. The combined effect is contrary to the historical intent under NSPS OOOO and NSPS OOOOa, which is to lessen the administrative burden while still achieving the desired environmental benefits. API believes that improving the clarity of the storage vessel applicability criteria is a worthwhile effort and offers the following redline for §60.5365b(e)(2)(i):

> *For purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit ~~must~~ may include the elements such as those provided in paragraphs (e)(2)(i)(A) through (F) of this section.*

6.2 The proposed requirements for a modification and reconstruction of a tank battery require additional technical clarifications.

EPA's proposed definitions of reconstruction or modification for a tank battery require several clarifications. First, the proposed definition for reconstruction is internally inconsistent. For a tank battery consisting of more than one storage vessel, reconstruction is based on replacing at least half of the storage vessels based on the assumption that "*the cost of replacing storage vessel components such as thief hatches and pressure relief devices, in comparison to the cost of constructing an entirely new storage vessel affected facility, will not exceed 50 percent of the cost of constructing a comparable new storage vessel affected facility*."[63] However, for a tank battery consisting of a single storage vessel, the existing provisions of §60.15 apply on the chance that the cost of replacement storage vessel components could be 50% or more of the cost to construction a comparable new storage vessel. Either the cost depreciable components on a storage vessel other than the tank itself could be 50% or more of the cost of a new comparable tank or not. Practically, this inconsistency means that operators would have to track the cost of storage vessel component replacements for single storage vessel tank batteries, but not for multi-vessel tank batteries. For both single and multi-vessel tank batteries, operators should have the option

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[63] 87 FR 74801-74802

to track either storage vessel replacements or all depreciable components. Based on this recommendation, API offers the following redline of §60.5365b(e)(3)(i):

> *"Reconstruction" of a tank battery occurs when the provisions of §60.15 are met for the existing tank battery ~~any of the actions in paragraphs (e)(3)(i)(A) or (B) of this section~~ and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section. As an alternative to the provisions of §60.15, an operator may determine reconstruction has occurred if at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> ~~*(A) The provisions of §60.15 are met for the existing tank battery ; as an alternative to the provisions of §60.15, At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or*~~
>
> ~~*(B) The provisions of §60.15 are met for the existing tank battery that consists of a single storage vessel.*~~

Secondly, EPA's proposed definition of modification requires clarification. API supports the first two proposed criteria for modification found in §60.5365b(e)(3)(ii)(A) and (B): "*A storage vessel is added to an existing tank battery*" and "*One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases*". Both these changes require capital expenditure on the potential affected facility (i.e., the tank battery) and would increase emissions. However, the proposed criteria in §60.5365b(e)(3)(ii)(C) and (D) regarding increases in liquid throughput are too broad and is inconsistent with §60.14(e)(2). Per 40 CFR 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification. EPA has not fully explained why it is proposing to deviate from the historical legal understanding of modification which requires both an increase in throughput and a capital expenditure on the storage vessel or tank battery. Also, increases in liquid throughput at well sites, central production facilities, and compressor stations are difficult to track as sites typically track liquid throughput using tank gauging rather than flow meters. Due to the historic understanding of modification and practical challenges of tracking liquid throughput, **API believes that §60.5365b(e)(3)(ii)(C) and (D) should be removed from the definition of modification.** [64]

However, if EPA decides to include increases in liquid throughput as a criterion for modification, API offers the following recommendations:

- **The increase in liquid throughput must also be accompanied by a capital expenditure on the tank battery itself.** Actions, such as drilling a new well or fracturing or refracturing an existing well, could increase liquid throughput and require capital expenditure but not necessarily on the tank battery itself.

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[64] Please see Section 11.6 of our comments on the original proposal for overarching legal comments on the proposed modification definitions. We note that EPA appears to have responded in part to these comments by providing that a modification to a tank battery occurs only when specified actions "result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii)" (the PTE-based applicability thresholds for storage vessels). But we note that EPA's proposed PTE criteria apply to an annual PTE and not, as specified in § 60.14, a short-term measure of PTE (such as lb/hr). This is a significant change in how a potential emissions increase should be considered in determining the existence of a modification because the annual PTE basis in practice likely results in a more expansive modification definition because the short term PTE of storage vessels in almost all cases will be much higher than an annual value, which means that more variation in actual short term emissions can be accommodated without triggering a modification than under an annual metric. EPA fails to explain why it has shifted from a short-term to an annual basis for determining emissions increases associated with a change. As a result, we do not have a reasonable opportunity to understand EPA's rationale and to provide meaningful comments.

These actions would not be considered modifications to the tank battery unless there is capital expenditure on the tank battery itself. This recommendation would make NSPS OOOOb consistent with NSPS A.

- **Reference to process unit in §60.5365(e)(ii)(C) should be removed since process unit is defined such that they should not exist at well sites and centralized production facilities.** Process unit is a term specific to natural gas processing plants and does not apply to well sites and centralized production facilities.

- **Well sites and centralized production facilities should also be allowed to compare liquid throughputs to limits in a legally and practicably enforceable permit like compressor stations and natural gas processing plants.** EPA should be consistent and allow well sites and centralized production facilities to compare liquid throughputs to limits in a legally and practicably and enforceable permit since such a permit can be relied upon for the PTE determination for all sites. **In the absence of a legally and practicably enforceable limit, all sites should be allowed to compare liquid throughputs to those used to design the existing cover and closed vent system in operation when a potential modification action occurs.** These recommendations would also make modification criteria consistent for all sites and clearly define what an increase in liquid throughput is.

Based on these recommendations, API offers the following redlines to §60.5365b(e)(3)(ii):

> *“Modification” of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through ~~(D)~~(C) of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> *(A) A storage vessel is added to an existing tank battery;*
>
> *(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; or*
>
> *~~(C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well).~~*
>
> *~~(D)~~(C) ~~For tank batteries at compressor stations or onshore natural gas processing plants,~~ A capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or ~~(D)~~(C) of this section) determination of the potential for VOC or methane emissions; or in the absence of a legally and practicably enforceable permit, a capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or (C) of this section) design of the storage vessel cover(s) and closed vent system.*

6.3 Additional technical clarifications to proposed definitions are warranted to clarify applicability of certain requirements for tank batteries.

Since the proposed requirements for NSPS OOOOb and EG OOOOc will apply for the tank battery, there are additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria. We support EPA's proposed definition for tank battery based on storage vessels that are manifolded together for liquid transfer, but offer a minor clarification on respect to its location as follows:

> *Tank battery means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant if only one storage vessel is present.*

This clarification addresses the situation of a single storage vessel not located at a well site, central production facility, compressor station, or natural gas processing plant (e.g., drip station along a pipeline). These storage vessels typically have low throughput and methane and VOC emissions. In §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii), EPA does not describe how to determine PTE for tank batteries at location other than a well site, centralized production facility, compressor station, or natural gas processing plant. Therefore, API believes that the agency did not intend to regulate these low-emitting tanks with these proposed rules.

6.3.1 The definition of compressor station must be clarified with respect to the storage vessel applicability provisions in §60.5365b(e).

With the introduction of the newly defined central production facility, an additional clarification is needed for when and how to calculate the tank battery PTE at well sites and central production facilities that may have compression versus at a compressor station. The EPA makes this distinction clearly for how to consider the fugitive emission monitoring by referencing §60.5397b in the definition of compressor station. As an example, consider a reciprocating compressor at an oil processing facility. The facility would be a "*tank battery at a well site or centralized production facility*" under §60.5365b(e)(2)(ii) and yet also a "*tank battery located at a compressor station*" as used in §60.5365b(e)(2)(iii).

We therefore request EPA also clarify the storage vessel requirements in a similar way by referencing of §60.5365b(e) in the definition of compressor station as follows:

> *Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of §60.5365b(e) and §60.5397b.*

In terms of the PTE calculations, centralized production facilities should be considered like compressor stations and natural gas process plants because the storage capacity is typically based on "a projected maximum average daily throughput". Therefore, API offers the suggested redlines for §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii).

> *(ii) For each tank battery located at a well site ~~or centralized production facility~~, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided*

> *in paragraph (e)(5)(iv) of this section. The potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.*

> *(iii) For each tank battery located at a centralized production facility, compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station or onshore natural gas processing plant or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.*

Another suggested solution is to harmonize the PTE calculation requirements for all sites based on the requirements proposed for compressor stations and gas plants.

6.3.2 A storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant used to alleviate dangerous, or emergency events must be clearly excluded from the definition of storage vessel.

At some facilities, storage vessels may be installed for the sole purpose of providing relief from pressure vessels during emergencies. Previously, these storage vessels would not trigger applicability as a single emergency use vessel was unlikely to exceed 6 tpy VOC threshold under NSPS OOOO or NSPS OOOOa. These tanks now present a challenge with the new applicability threshold proposed in NSPS OOOOb and EG OOOOc for the tank battery. At the state level, emergency use tanks are exempt from control requirements from states and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.[65,66] We request EPA provide an exclusion for emergency use tanks from the definition of storage vessel as follows:

> *Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:*
>
> - *Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180*

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[65] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[66] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

- *Process vessels such as surge control vessels, bottoms receivers or knockout vessels.*
- *Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.*
- *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

6.3.3 EPA should clarify that location is not a restriction on the use of a floating roof tank.

In §60.5395b(b)(2), EPA correctly prohibits the use of a floating roof if the storage vessel or tank battery has flashing emissions. However, EPA also prohibits the use a floating roof at a well site or centralized production facility. Flashing emissions alone, regardless of location, should prohibit the use of a floating roof tank because flashing emissions, not location, could prevent proper operation of a floating roof.

API offers a recommended redline in Comment 6.5.

6.4 The requirement to manifold the vapor space of each storage vessel in the tank battery is overly prescriptive and unnecessary.

As part of the control requirements for storage vessel affected facility, EPA proposes that "*The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery*"[67]. This requirement to manifold the vapor space of each storage vessel in a tank battery is unnecessary and restricts an operator's flexibility in achieving compliance with the required 95% emissions reduction. An operator should be able to install any number of control devices and manifold the vapor space of the storage vessels from one or more tank batteries into one or more closed vent systems so that each control device is properly sized for the expected vent gas flow rate.[68] The requirement to manifold the vapor space of a tank battery may also cause confusion with the proposed definition of tank battery which is based on storage vessels manifolded together for liquid transfer.

API offers a recommended redline in Comment 6.5.

6.5 EPA should provide an exemption from control requirements due to technical infeasibility if the control device or VRU would require supplemental fuel.

With the change in affected facility from a single storage vessel to a tank battery, control devices will be required for a longer time compared to NSPS OOOO and NSPS OOOOa – until the actual uncontrolled emissions from the tank battery (versus each individual storage vessel) are below 4 tpy VOC and 14 tpy of methane. This longer

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[67] §60.5395b(b)(1)(ii)

[68] If not corrected, EPA's failure to consider these obvious and important aspects of its proposed manifolding requirement would render such a requirement arbitrary and capricious. Motor Vehicle Mfrs. Assn. v. State Farm Mut. Automobile Ins. Co., 463 U.S. 29, 43 (1983).

period for the control requirement will increase the likelihood that some control devices or VRUs will require supplemental fuel to be technically feasible. As discussed in Comment 5.6.3 for control device pilot flames, operators may have to bring propane for supplemental fuel for sites without fuel gas or burn additional sour fuel gas. As such, API recommends EPA consider an exemption from control requirements for a tank battery if use of a control device or VRU would be technically infeasible without supplemental fuel for pilot flame or other purposes. Such exemptions currently existing in state regulations for storage vessels and tank batteries including Colorado. Based on the language for the Colorado exemption, API offers the following recommended redlines to the control requirements in §60.5395b(b), which also includes the previous comment:

Control requirements.

(1) Except as required in paragraphs (b)(2) and (b)(3) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through ~~(iv)~~ (iii) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);

~~*(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;*~~

~~(iii)~~(ii) The tank battery must be equipped with ~~a~~ one or more closed vent systems that meet~~s~~ the requirements of §60.5411b(a) and (c); and

~~(iv)~~(iii) The vapors collected in paragraph~~s~~ (b)(1)(ii) ~~and (iii)~~ of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) For storage vessel affected facilities that do not have flashing emissions ~~and that are not located at well sites or centralized production facilities~~, you may use a floating roof to reduce emissions. If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb. You must submit a statement that you are complying with §60.112b(a)(1) or (2) with the initial annual report specified in §60.5420b(b)(1) and (8).

(3) You may apply to the Administrator for an exemption from the control requirements in paragraphs (b)(1) of this section if the use of a control device would be technically infeasible without supplemental fuel. Such request must include documentation demonstrating the infeasibility of the control device.

7.0 Natural Gas-Driven Pneumatic Controllers

Pneumatic controllers play a pivotal role in the safe operations at oil and natural gas facilities – including at well sites, central productions facilities, compressor stations, and processing plants. In our review of the proposed requirements EPA has not adequately addressed some of the major concerns we identified in our January 31, 2022 comment letter.[69] EPA has severely overstated the deployment capabilities for solar installations to power oil and gas infrastructure in support of their proposal, which indicates a continued lack of understanding of how pneumatic controllers (and pneumatic pumps) would be converted to achieve a non-emitting standard.

For NSPS OOOOb, we support the use of non-emitting pneumatic controllers, contingent on clarifications as described herein, for newly constructed, modified or reconstructed well sites, central production facilities, and compressor stations. We also support EPA excluding emergency shutdown devices from these provisions as it allows for safety in case of emergency.

For existing natural gas-driven pneumatic controllers under NSPS OOOOc, we continue to maintain that 1) adequate time and phase-in must be provided to properly account for the magnitude and scale of sites converting to non-emitting controllers and 2) it is most appropriate to focus conversion to non-emitting controllers at facilities with the largest number of controllers (see Comment 7.5). To effectively do this, the use of low continuous bleed or intermittent natural gas-driven pneumatic controllers should be allowed and should be monitored periodically for proper functioning at the frequency specified in §60.5397c. An initial analysis[70] of the potential impact of the rule should it require conversion to non-emitting pneumatic controllers at all existing facilities shows that it could result in the premature shut-in of a significant percentage of existing wells, particularly when considered in context with the proposed monitoring requirements[71]. EPA should allow additional flexibility in this area as we have described to allow states to preserve the remaining useful life of facilities.

7.1 Adequate implementation time must be provided for pneumatic controller and pneumatic pump requirements under both NSPS OOOOb and EG OOOOc.

As we have stated earlier, adequate time is required to implement the proposed control standards as they fundamentally shift how pneumatic controllers and pneumatic pumps have typically been operated. While new surface locations can typically plan for controls during site design, the supply chain delays pose a genuine and significant concern for all aspects of implementing the pneumatic controller requirements. Anecdotal evidence from one operator that is currently conducting retrofits in New Mexico has identified that air compression equipment is in short supply with around 8 months of delays and another operator that has been piloting solar panel instrument air systems is now experiencing delays of 18 to 24 months on previously made orders. While eventually the market will rise to meet this demand, that market correction has not yet been realized and presents very real concerns for our members. Currently there are hundreds of operators attempting to order equipment for thousands of sites. While we are generally supportive of the proposed requirements (with the necessary and specific clarifications that we have requested), the current proposed timeline for compliance is unrealistic due to global circumstances beyond any operator's ability to control or influence.

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[69] EPA-HQ-OAR-2021-0317-0808

[70] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API's request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

[71] See Comment 2.0

As anecdotal evidence, our members operating in New Mexico are currently working through retrofits of facilities in compliance with state regulations. Instrument air systems are currently on backorder with a wait time of approximately 8 months. This wait time is expected to be exacerbated when EPA's final rule takes effect. Once equipment is received, only 1-3 facilities can be retrofit per operator per week based on type or size of the facility, weather conditions, etc. This means for any given operator, only approximately 50-150 retrofits can successfully take place in a single year. For operators with thousands of new, modified and existing locations, the current proposed timelines are untenable.

Based on EPA's proposed November 2021 applicability date, there are thousands of sites that may now require retrofit under NSPS OOOOb. Since operators are currently experiencing 6-to-8-month delays in acquiring the necessary control equipment for instrument air system conversions, we suggest EPA amend the requirements to reference "upon receipt of equipment" similar to how certain delay of repair provisions have been framed within other regulations.

For pneumatic controllers and pumps under EG OOOOc, given all of the existing sites in the U.S. and the implementation aspects outlined above, we continue to have serious concerns that 5 years for conducting retrofits of this magnitude would not provide adequate time given current and anticipated supply chain delays. Because of these constraints for EG OOOOc, EPA should consider a longer phase-in period where facilities with the largest number of controllers are retrofit first.

7.2 For NSPS OOOOb and EG OOOOc, EPA should allow the routing of emissions from natural gas-driven controllers to a control device.

We continue to suport the routing of certain controller emissions to a flare or other combustion device. In its analysis, EPA dismisses this option by finding that routing pneumatic controller vent gas to a process is cost-effective and thus BSER; however, EPA's analysis fails to account for the cost-effectiveness of the incremental 5% of methane and VOC emissions reductions achieved when comparing routing to process against routing to a control device, which conservatively assumes a control device will achieve only 95% reduction.[72] In many cases, the actual performance of a control device exceeds 98% control. Instead, EPA's analysis focuses on the cost-effectiveness of no control against 100% control. API requests that EPA include routing to a control device as a compliance standard under NSPS OOOOb and EG OOOOc. If EPA does not adopt routing to a control device as an emissions reduction standard, it must demonstrate as cost-effective the incremental 5% of emissions reductions achieved through routing to a process or converting to instrument air.[73]

As an example, one facility may choose to install an instrument air system to convert most natural gas-driven pneumatic controllers on site, but emissions from certain types of controllers that are associated with the flare system itself (e.g. back pressure valve[74]) could more easily route emissions to the flare header. By EPA not allowing for this site configuration, some operators may need to reconfigure controllers that are currently already

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[72] 87 Fed. Reg. at 74765-66.

[73] As further support for the above, API responds to EPA's request for information regarding whether vapor recovery units (VRU) are ever necessary to route pneumatic controller vent gas to a process. While it is feasible for operators to route pneumatic controller vents to a downstream process that operates at a lower pressure, a VRU is necessary if no such lower-pressure destination exists or is of limited availability. Installation of a VRU is capital intensive, and VRU maintenance is costly and challenging, especially in extreme weather climates. Where downstream process pressure exceeds vent gas pressure, the pneumatic controller vent gas cannot feasibly route to a downstream process without compression. If EPA is unwilling to allow routing of pneumatic controller vent gas to a control device as an emissions reduction standard on the same footing as routing to a process, EPA should allow routing to a control device where routing to a process is infeasible (taking into account technical and economic considerations), and define infeasibility to include scenarios where routing to a process requires a VRU.

[74] Back pressure valves can be routed to the flare when they are in close proximity to the flare header since they only actuate when there is an over pressurization.

routed to a flare or other combustion device. In this scenario, VOC and methane emissions from these routed controllers are already reduced by 95% or more. EPA has provided no basis for not authorizing routing to control as an option.

Adopting this methodology as a compliance standard can be achieved by amending the proposed definition of “self-contained pneumatic device” to include natural gas-driven controllers routed to control devices in that definition (refer also to Comment 7.3). Such a revision is consistent with both New Mexico and Colorado’s regulations – which define non-emitting to include pneumatics routed to combustion.

7.3 Additional technical clarifications are warranted to clarify applicability of certain natural gas-driven pneumatic controller requirements.

While we support inclusion of flexible solutions to reduce emissions from natural gas-driven pneumatic controllers, we have identified critical aspects of the proposed provisions that require technical clarification or simplification as we have outlined herein.

7.3.1 Suggested clarifications to certain proposed definitions related to pneumatic controllers in NSPS OOOOb and EG OOOOc.

There are some additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria as proposed. There are many types of automated instruments that maintain a process condition that are not pneumatic controllers. Many of the proposed definitions must clearly identify pneumatic controllers from these other instruments and be more specific to avoid confusion.

> ***Bleed rate*** *means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a fixed orifice in a pneumatic controller.*
>
> ***Continuous bleed*** *means a natural gas-driven pneumatic controller that is designed with a continuous flow of ~~pneumatic supply~~ natural gas from ~~to~~ a fixed orifice~~ pneumatic controller~~.*
>
> ***Non-natural gas-driven pneumatic controller*** *means an automated process control device that utilizes instrument air or hydraulic fluid as the motive force to change valve position. ~~Instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.~~*
>
> ***Pneumatic controller*** *means an automated instrument that manipulates a valve’s position with pressurized gas to ~~used for~~ maintain~~ing~~ a process condition such as liquid level, pressure, delta-pressure and temperature.*
>
> ***Self-contained pneumatic controller*** *means a natural gas-driven pneumatic controller in which the motive gas is not vented to the atmosphere but captured ~~releases gas~~ into t~~he~~ downstream piping for process use, sales or control such that there are no direct methane or VOC emissions from the controller.~~, resulting in zero methane and VOC emissions~~*

7.3.2 EPA must clarify the pneumatic controller requirements in NSPS OOOOb and EG OOOOc apply after startup of production and to stationary equipment only.

We agree with EPA'a assertion in the preamble where (87 FR 74759) *"The EPA acknowledges that the focus of the BSER analysis has been on stationary sources and pneumatic controllers that are part of the routine operation of oil and natural gas facilities."* The zero-emissions requirements are not justified for short term controller usage related to non-stationary sources.[75] Retrofitting controllers located on temporary equipment requires significant engineering design that has not been adequately evaluated to identify if these options are even possible, nor technically achievable nor practically attainable. Pneumatic controllers located on temporary or portable equipment should be allowed to operate as low-bleed or intermittent as needed for proper functioning of the temporary equipment. Some examples of temporary equipment or activities that should be excluded from the proposed provisions include the following:

- **Temporary Equipment (such as compressors):** Operators may utilize a small injection compressor to assist in ramping up production for new wells that have recently ended flowback. These compressors are typically skid mounted and located on site for as few as 30 days after the startup of production. These compressors contain a handful of pneumatic controllers to assist in proper function on the unit and may sometimes be leased from a third party. Another example is the use of a temporary compressor at a wellsite that is needed in anticipating gathering system high line pressure during new gathering system infrastructure build-out, which may occur for a few months. We ask that EPA exclude any natural gas-driven pneumatic controllers on equipment that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 180 consecutive days. This approach is consistent with language describing applicability of temporary storage vessels under NSPS OOOO, NSPS OOOOa, proposed NSPS OOOOb, and proposed EG OOOOc.

- **Drilling and Completion Activities:** As EPA is aware, drilling and completion activities require specialized temporary use equipment that is often contracted by third-party operators. Any pneumatic controllers associated with drilling and completion equipment should be excluded from the zero-emitting controller requirements, which can be accomplished by clarifying that the requirements for pneumatic controllers are not applicable until after the startup of production like other provisions within the proposed standards.

7.3.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic controllers.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms 'natural gas-driven pneumatic controller' and 'pneumatic controller' interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic controllers. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric controllers at the well site as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(d)(1):

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[75] Exemption of controllers on temporary equipment is consistent with state regulations in New Mexico and Colorado.

> *For the purposes of §60.5390b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more.*

We offer a suggested redline for reconstruction below in Comment 7.3.4.

To be clear, our support for the proposed provision as it relates to modification for natural gas-driven pneumatic controllers is contingent on this and the other clarifications requested throughout Comment 7.3. Absent these clarifications then we maintain our previous position submitted in our January 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) and request EPA streamline applicability across various affected facilities by defining modification for the collection of natural gas-driven pneumatic controllers and pneumatic pumps like how EPA has defined modification for the collection of fugitive components at well sites and compressor stations. For central production facilities, modification should be based on an increase in designed throughput capacity with the addition of a storage vessel at the central production facility as we further elaborate in Comment 2.6.

7.3.4 Under NSPS OOOOb, reconstruction for natural gas-driven pneumatic controllers should not include replacement of a high-bleed natural gas-driven controller with a low-bleed or intermittent controller.

Many of our members have committed to the elimination of all remaining high-bleed controllers that may still be in use at existing locations. As we included in our January 31, 2022 comment based on data submitted to EPA through EPA's Greenhouse Gas Mandatory Reporting Program, data extracted for the 2020 calendar year clearly shows the breakdown of high-bleed natural gas-driven pneumatic controllers is only around 2% of total reported natural gas-driven pneumatic controllers across both the onshore production segment and onshore gathering and boosting segments. This indicates there are not many high-bleed devices left in operation at well sites, central production facilities, and compressor stations based on successful implementation of NSPS OOOO and NSPS OOOOa over the last decade.

Replacement of these last remaining high-bleed controllers with low-bleed or intermittent controllers would equate to an overall reduction in methane and VOC emissions and should not be included in the reconstruction provisions as this could disincentivize short term benefits of this type of replacement. With the implementation of EG OOOOc coinciding with proposed NSPS OOOOb, this clarification will only delay conversion to non-emitting without impacting current investment in equipment upgrades in the near term that provide immediate environmental benefit.

We offer the following suggested redline to §60.5365b(d)(2) to address these concerns and the clarification explained in Comment 7.3.3:

> *§60.5365b(d)(2): For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of existing natural gas-driven pneumatic controllers at the site in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic controllers is replaced. That is, if*

> *an owner or operator meets the definition of reconstruction through the "number of controllers" criterion in (d)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of natural gas-driven pneumatic controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic controller replacement. Replacement of an individual natural gas-driven controller with a continuous bleed rate greater than 6 scfh with either a natural gas-driven controller with a continuous bleed rate less than 6 scfh or with an intermittent vent natural gas-driven pneumatic controller is excluded from this determination.*
>
> *If the owner or operator applies the definition of reconstruction in §60.15(b)(1), reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven pneumatic controllers at the site. The "fixed capital cost of the new pneumatic controllers" includes the fixed capital cost of all natural gas-driven pneumatic controllers which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].*
>
> *If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic controllers that are replaced, the owner or operator must also comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review.*

7.3.5 Additional clarifications are required to the proposed requirements for reconstruction of pneumatic controllers.

In review of the proposed regulatory text provided for §60.5365b(d)(2), the following are elements of the proposed regulatory text require clarification.

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed in §60.5365b(d)(2).** The proposed language in §60.5365b(d)(2)(ii), suggests that reconstructed natural gas-driven pneumatic controllers would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic controllers. We believe it was EPA's intent to

not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 Supplemental Proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 Supplemental Proposal.

7.4 Self-contained natural gas-driven controllers should follow the requirements for fugitive emission monitoring, not those for closed vent systems.

Self-contained natural gas-driven pneumatic controllers are configured to route emissions into the downstream piping, which is simply a hard piece of pipe with connectors or flanges. Given the simplicity and low potential for leaks or defects along the piping, EPA is correct in allowing OGI inspections, but we believe operators should follow the work practice for the fugitive emission monitoring requirements §60.5397b and not the NIE provisions as proposed.[76] EPA should also allow inspection of self-contained pneumatic controllers via the alternative screening techniques program, when applicable.

We also note that as proposed, the self-contained pneumatic controller requirements do not articulate repair or contain delay of repair provisions or timelines and we believe this was not EPA's intent. Given self-contained pneumatic controllers would more commonly occur on pressure control valves, the operator would likely need to shut-in the well or shutdown equipment in order to conduct any sort of repair (if any were found). We therefore request, at a minimum, that repair timelines in §60.5397b(h) and specifically the delay of repair provisions as described in §60.5397b(h)(3) apply to self-contained natural gas-driven pneumatic controllers.

As we mention in Comment 2.4, we encourage EPA to streamline how periodic monitoring in the proposed rules is conducted by following a consistent set of requirements including the frequency, repair schedule, and retention of associated records. This will provide clarity across all affected facilities at a site where monitoring is occurring.

7.5 For EG OOOOc, locations without access to electrical power should have the option to use low continuous bleed or intermittent bleed natural gas-driven pneumatic controllers with proper functioning confirmed through periodic monitoring until modification or reconstruction triggers NSPS OOOOb. At a minimum, EPA must consider an allowance for low production well sites and/or sites with a limited number of natural gas-driven controllers from retrofit within EG OOOOc.

Many existing well sites are low producing wells that could be close to end-of-life of their production cycle and may only contain a limited number of controllers. The complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production versus implementation of the collective costs associated with EG OOOOc. The BLM acknowledged this fact in their proposed Waste Prevention Rule by establishing an exemption of retrofit of pneumatic controllers based on facilities *"producing at least 120 Mcf of gas or 20 barrels of oil per month"* because *"it is unlikely that an*

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[76] Should EPA continue to apply NIE as a numerical standard for self-contained pneumatic controllers, it could disincentivize conversion.

operator of a lease, unit, or CA producing only 120 Mcf of gas or 20 barrels of oil per month could re-direct the entirety of its revenues for 10 months towards paying for upgrading its pneumatic equipment."[77]

In our previous comment letter submitted January 2022, we supported retrofit for facilities with at least 15 controllers at a well site, central production facility, or compressor station. There have not been any drastic changes in actual costs to retrofit facilities or technical feasibility of implementing these types of retrofits in locations that do not have access to grid power. In fact, due to other similar regulations currently being implemented at the state level, the timeline for acquiring the necessary equipment is long due to supply chain limitations, and skilled labor is in short supply and high demand. We maintain our position that at these existing facilities any high-bleed natural gas-driven pneumatic controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company's fugitive emission monitoring program to monitor for proper functioning. The recordkeeping and reporting for these devices should follow requirements associated with fugitives and not have a separate set of requirements as currently proposed for sites in Alaska.

7.5.1 Spacing constraints at existing sites may cause technical infeasibility for converting to non-emitting controllers where grid power is not available.

Existing well site sites, central production facilities or compressor stations may have sizing constraints for the proper placement (due to safety and other permitting constraints) of instrument air control systems. Examples include an instrument air compressor that must sit outside of classified areas, generators, and/or or solar panels.

To retrofit a facility with an instrument air system, an engineer first verifies that adequate power is available and then applies for necessary state level permits, which takes approximately 60 days to acquire (if approved). On federal lands, this type of project would require reopening permits pursuant to National Environmental Policy Act, which is around a 12 to 18 month permitting process. On private lands, an operator may not be able to purchase additional land from the private owner.

During construction, an instrument air header and compressor skid must be added to the facility. The air compressors must sit outside of classified areas and therefore, some older reclaimed facilities may not have adequate space to add necessary equipment for the instrument air system because the air compressor must be placed outside of a safe radius from existing flares and other hydrocarbon-containing equipment (e.g. limitations due to electrical classifications). If accessible grid power is not available, a generator would have to be installed to power the air compressor, which would emit other pollutants.

7.5.2 Case Study Review for Land Required for Solar Retrofits

For existing medium and larger production sites and tank batteries, larger solar installations will be required to transition the sites to the proposed zero-emitting standard. As a case study, multiple sample sites throughout the country were evaluated to determine the space requirement for a solar installation that is equivalent to the energy of an instrument air system requiring 112 kilowatts (kW), which would be needed for large facilities not included in EPA's model plant analysis. Results are presented in Table 1.

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[77] 87 FR 73606

This case study highlights that the land requirement for many sites is likely to be between 0.6 – 1.5 acres. Several key considerations to consider when installing solar panels at existing well sites that hinder the compatibility include:

- Site area footprints have already been agreed to and installing large arrays will require revisiting existing agreements to modify, a time consuming and costly process. Many jurisdictions, including the BLM, prefer smaller facility footprints.
- Site layout is already optimized for existing infrastructure to fit within a facility area.
- Adding in solar infrastructure of panels, wiring, battery, etc. could lead to complications and unnecessary safety hazards as batteries are introduced near hydrocarbons.
- Snowfall is prevalent in many of these regions and will reduce efficiency of the optimally angled panels. Vertically oriented arrays to prevent snowfall interference may not be appropriate in all circumstances unreasonable given the climate, wind, and remote nature of these sites.

Table 1. Case Study – Physical Land Requirement for Solar Installations Replacing Power Supply for 112 kW Generator

Site Location	Optimally Angled Panels[a]					Vertically Angled Panels[b]				
	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage[g]
	kW	degrees	Hours			kW	degrees	Hours		
Carlsbad, New Mexico	620	28	5.1	2,067	0.7	1513	90	2.1	5,044	0.9
Midland, Texas	620	28	5.1	2,067	0.7	1558	90	2.0	5,193	0.9
Arnett, Oklahoma	735	30	4.3	2,452	0.8	1318	90	2.4	4,392	0.8
Denver, Colorado	719	31	4.4	2,396	0.8	1171	90	2.7	3,904	0.7
Pinedale, Wyoming	988	33	3.2	3,294	1.1	1091	90	2.9	3,635	0.6
Williston, North Dakota[h]	1318	35	2.4	4,392	1.5	1091	90	2.9	3,635	0.6

a. Optimally angled tilt (annual average) determined from National Renewable Energy Lab (NREL)'s PVWatts® Calculator; https://pvwatts.nrel.gov/pvwatts.php

b. Vertically angled systems were suggested by Clean Air Task Force at EPA-HQ-OAR-2021-0317-1451.

c. Size of installation determined from Omni calculator methodology required inputs of electricity consumption and solar hours per day to determine roof area of solar panels; https://www.omnicalculator.com/ecology/solar-panel

d. Using NREL's PVWatts calculator in conjunction with the Omni calculator, it was determined roof area was equal to ground area for simplification as, there was a <1% difference in annual kWH production.

e. Footprint Hero was used to determine the lowest monthly average daily peak sun-hours for each location for both panels at optimal angle and 90 degrees; https://footprinthero.com/peak-sun-hours-calculator

f. Number of panels based on average panel output of 300 watts and 15 square feet.

g. Acreage for vertically angled panels assumes panels would be stacked two panels high.

h. The high latitude of Williston, North Dakota has the lowest monthly average daily peak sun-hours when the solar array is optimally positioned. When vertically positioned the peak sun hours increases from 2.4 hours to 2.9 hours.

EPA should also consider the following in conjunction with results of this analysis:

- the cost of land acquisition;

- right-of-way and easement concerns/limitations;
- projection of further land-use change requirements for solar installations; and
- percent of further land use change required for solar installations on designated wetlands.

For existing locations without accessible grid power and where there is an ability to acquire additional land to use solar or natural gas generators, operators will not have the ability comply with the current proposal.

7.5.3 The incremental costs and benefits have not been adequately justified at existing locations.

Within the technical Support documentation, EPA does include a scenario for monitoring intermittent vent controllers. Based on EPA's own assumptions, this type of program can achieve 96.7% reductions in emissions (based on emission factors) for an overall site level control efficiency of 65% based on semi-annual OGI monitoring. Since many large facilities within the proposal will be required to conduct quarterly OGI, we anticipate this control efficiency to be even higher.

Furthermore, since all well sites, central production facilities and compressor stations will already be subject to fugitive emission monitoring at some frequency, the incremental cost to implement such a program for pneumatic controllers would be solely based on the additional recordkeeping and reporting that an operator would need to implement. The incremental costs and benefits associated with the zero-emitting provisions in comparison with this option to monitor controllers for proper functioning within a company's LDAR program, have not been adequately justified given the numerous technical infeasibility challenges communicated with implementing solar-powered electric controllers, spacing constraints at some existing facilities to install certain equipment, and other emission offsets that will stem from implementing other forms of power generation.

In EPA's analysis, the emission reductions from inspections of intermittent vents are based on emission rates assumed to be halfway between perfectly operating post-inspection controllers and the overall emission rate that includes both perfectly operating and malfunctioning controllers. This suggests that EPA has no data or understanding of how often intermittent bleed devices may not function properly, which is an important distinction given the expected costs of implementing these requirements at all locations as proposed under EG OOOOc.

7.6 EPA's cost-benefit analysis significantly underestimates the costs of implementing the proposed zero-emissions standard and overestimates the technical capabilities of solar and electric controllers.

In our January 31, 2022 comment letter, we provided detailed comments on the technical challenges that operators within U.S. are facing as they convert facilities to electricity, pilot solar powered instument air systems, and install natual gas-driven instrument air systems, which we incorporate again by reference.[78] As our members begin to plan, design and install zero-emitting penumatic controllers, it is clear that EPA has not adequately accounted for the costs of this proposal; especially with respct to retrofit of existing facilities. Total project costs, including equipment and labor, to retrofit a large gathering and boosting compressor station could exceed $1,000,000, which is substantially higher than EPA's projections.

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[78] Comments found in EPA-HQ-OAR-2021-0317-0808

Upon review of the supplemental techncial Support Document, we have found EPA's cost-benefit analysis to significantly underestimate the cost (especially for retrofit of existing facilities) and overstate the techncial feasibility of making these retrofits as summarized below:

- EPA applied an emission factor for low-bleed pneumatic controllers, with a factor that by definition would be a high-bleed pneumatic controller. EPA has justified this update within the model plant by aligning the model plant to the proposed changes to Subpart W which is 6.8 scf/h. This emission factor is nearly a five-fold increase to the continuous low-bleed device emission factor; is greater than the threshold that had been applied to determine whether a device should be categorized as low-bleed or high-bleed; and a device with this level of emissions would not be allowed pursuant to NSPS OOOO or NSPS OOOOa. In our review of the proposed changes to Subpart W, we have asked EPA to provide the details of how this factor was determined as there is little documentation supporting this change. Regardless, it is an inappropriate factor for applying to a low-bleed device for NSPS OOOOb and EG OOOOc because an operator would not be able to install a continuous bleed natural gas-driven pneumatic controller with this manufacturer rating as it is considered a high-bleed pneumatic controller.
- EPA continues to describe application of solar-powered and electric controllers as being directly powered by the grid or solar technology in the model plant analysis. Operator experience is that sufficient air is required to properly control the pneumatic controllers, where an instrument air system (i.e., an air compressor and associated equipment and piping) is required in nearly all applications. Electric controllers lack the speed and performance of gas-powered or air-powered actuators and there are limited equipment configurations where electric controllers are technically feasible. Specifically, electric controllers have inadequate duty cycle ratings, and the torque ratings are typically too low for reliable performance. This significantly limits the utility of electrically actuated controllers. Even if they performed comparably to gas-powered actuators, electrically actuated controllers have a higher failure rate, especially for throttle service where the actuator is constantly adjusting based on process conditions instead of at a set point. The modelled analysis for these scenarios incorrectly estimates the cost-effectiveness of the proposed requirements.
- Application of solar technologies as it pertains to gathering and boosting compressor stations have not been adequately reviewed in EPA's model plant analysis. The production sector model plants are geared toward small well sites with only 4, 8 and 20 controllers analyzed. Larger facilities, i.e., those with more than 20 pneumatic controllers, are still not adequately accounted for.
    - The assumptions made by EPA in the model plant analysis severely underestimate the air compressor horsepower and instrument air needs for sites with more than 20 controllers. These smaller scale cost metrics will not linearly scale up with larger facilities where a new instrument air header and piping may need run across the larger Gathering & Booster station site and additional pipe supports or extended pipe rack may be necessary. In our January 31, 2022 comment letter we provided information on facilities using instrument air systems to power over 100 controllers.
- In a case study published by NREL[79], solar panel capital costs for off-grid production well sites are 2.7 times the cost of grid-connected well sites. This does not align with EPA assumptions.
- EPA's model plant assumptions do not adequately address costs associated with retrofit of existing facilities. We note that installation also necessitates the facility be temporarily shut in/shut down to

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[79] https://www.nrel.gov/docs/fy20osti/76778.pdf

perform retrofits, which does not appear to be accounted for. Additional costs for retrofit at existing facilities that are missing from EPA's analysis include:

  - Additional Land Requirement for Solar Panel Installation including acquisition costs.
  - Site Preparation – For existing sites with tree lines, trimming may be required to maximize sun exposure. Additionally, for larger sites with more significant solar installations, foundation prep including concrete slabs was not considered.
  - Solar panel maintenance and cleaning particulate accumulation.
  - Permitting[80], Insurance and inclusion of battery boxes to house batteries in cold regions do not appear to be accounted for.
  - Retrofits often require the existing methane pipe headers to remain in place as a source of fuel gas for on-site equipment (compressors, fired heaters, combustors/TO's, flares, etc.) and a new parallel air header needs to be run to a to all instruments. This can add significant costs depending on the site layout, if there is available space in the existing pipe rack and facility, or if additional pipe supports are also needed.

- While EPA recounts and summarizes the significant number of comments criticizing solar-powered controllers (87 FR 74764), the primary underlying basis to EPA's economic and technical feasibility analysis pertaining to the conversion of existing, natural gas-powered pneumatic control systems to zero-emission systems (e.g., electric, solar-powered) is based on a single report: *Zero Emission Technologies for Pneumatic Controllers in the USA initially published in August 2016 and then updated in November 2021 by Carbon Limits (on behalf of the Clean Air Task Force).*[81] The report and EPA's application of report costs within the model plant analysis have a number of flaws as we have described herein and as follows:

  - The 2021 Carbon Limits report authors primarily gathered information through interviews with three technology providers and two oil and gas companies, both production-oriented companies with limited application of the technologies. The report is based on installation of solar-powered instrument air systems at only 22 onshore production sites located in Alberta, Canada, Wyoming, Utah, and Peru. This is an extremely small sample size for a technology to be deemed technically feasible and cost effective for all U.S.-based oil and natural gas operations. In response to our comments Clean Air Task Force states "Some of the interviewed technology providers have installed these systems in over 400 well-sites." Again, this is a rather small population when considering the number of facilities that will be applicable to these rules.

  - The Carbon Limits report focuses on reliability of solar power systems in colder climates, not areas with limited sun exposure. The Canadian provinces cited in the study, Alberta and British Columbia, experience very large amounts of sunshine, supporting the idea that solar power

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[80] https://www.solarpermitfees.org/SoCalPVFeeReport.pdf

[81] This basis was explicitly stated by EPA on page 46 of 173 to document Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS), 40 CFR Part 60, subpart OOOOc (EG) (October 2022). EPA states, "The EPA notes that the primary basis for the costs used for the November 2021 analysis was not the White Paper, but rather a 2016 report by Carbon Limits, a consulting company with longstanding experience in supporting efficiency measures in the petroleum industry.The analysis was updated to reflect the information in the 2022 Carbon Limits report."

generation works best in areas with more sun. The study does not support reliability of solar powered systems in areas of limited sun exposure like West Virginia.

- Identified calculation errors and assumptions in the model plant analysis:
  - The EPA cost analysis appears to contain a calculation error in determining the annualized project cost; while a solar panel lifespan of 10 years was stated, a value of 15 years was used in the annualization, resulting in a 30% annual cost difference. See tabs in Supplemental TSD Ch 3 Pneumatic Controllers.xlsx tabs *BSER T&S new, BSER T&S existing, BSER Production new, and BSER Production existing.*
  - The EPA capital cost analysis for electric compressor retrofit at existing transmission, storage, and production sites does not consider applications greater than 10 hp (highest compressor and associated equipment (e.g., dryers, wet air receivers) is capped at $32,000). Larger-sized systems should be evaluated.
  - For electric powered compressed air systems, EPA applied an annualization period of 15 years. If the compressor equipment life is updated to reflect the 2021 Carbon Limits Study provided value of 6 years, this option is not economically feasible. It is unclear why EPA deviated from the Carbon Limits study for this assumption and not others.
  - Carbon Limits updated certain assumptions in the 2021 report release. For some assumptions, EPA continues to retain costs from the 2016 study, without explanation.
  - The Carbon Limits report assumed a greenfield installation factor of 1.5 times major equipment costs without any adequate explanation. Member experience suggests this is closer to 3 to4 times equipment costs.
  - EPA continues to assume at least 1 high-bleed pneumatic controller is present at existing source model plants, when the data submitted to EPA pursuant to 40 CFR Part 98, Subpart W suggests this is an incorrect assumption given the low number of high-bleed controllers still being reported. See Attachment C in EPA-HQ-OAR-2021-0317-0808.
  - The EPA deflated costs provided in 2021 dollars to 2019 dollars. As inflation continues to be elevated, this is an unrealistic assumption and not reflective of actual, or anticipated costs. Costs continue to increase across the economy. A more appropriate assumption would be to assume 2021 dollars are equal to 2019 dollars.

7.7 Recordkeeping and Reporting

As more surface site locations electrify pneumatic controllers over time, confirmation of compliance would be easily obtained through any inspection of a site that was connected to grid power, using solar panels or other instrument air system. Based on review of the issued reporting form (EPA-HQ-OAR-2021-0317-1536_content), it appears EPA’s intent was to streamline recordkeeping and reporting to only natural gas-driven controllers, which are the affected facility. However, the language proposed within NSPS OOOOb per §60.5420b(c)(6)(i) and EG OOOOc is unclear in this regard. EPA should not require recordkeeping or reporting on pneumatic controllers that are not natural gas-driven.

8.0 Natural Gas-Driven Pneumatic Pumps

8.1 The applicability date for pneumatic pumps under NSPS OOOOb should be the date of the Supplemental Proposal.

While we maintain that the applicability of NSPS OOOOb should apply based on the December 2022 Supplemental Proposal, which included regulatory text for all affected facilities, this is particularly true for natural gas-driven pneumatic pumps. In the preamble (87 FR 74770)[82], EPA even acknowledges the proposed rule varies significantly from what was described in the November 2021 description for pneumatic pumps:

> ***The proposed NSPS OOOOb requirements in this Supplemental Proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition.*** *As noted above, in the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven pneumatic pump. In this Supplemental Proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site.*
>
> ***…****Specifically, the EPA is proposing that pneumatic pumps not driven by natural gas be used.* ***This is a significant change from the November 2021 proposal,*** *which would have required that emissions from pneumatic pump affected facilities be routed to control or to a process, but only if an existing control or process was on site****. (emphasis added)***

In these statements EPA acknowledges that not only did the affected facility definition expand to the collection of pumps at a site, but it also expanded to include piston pumps, which have not historically been regulated in NSPS OOOOa. Additionally, the proposed control options under NSPS OOOOb are completely unexpected and the hierarchy of options proposed would not have been a logical expectation based on the description in November 2021 proposal description. Specifically, operators have had no way of knowing:

1) Piston pumps would be affected facilities under §60.5365b(h).

2) The collection of both piston pump and diaphragm pumps would constitute an affected facility under §60.5365b(h).

3) The control standard would require a zero emissions control or a suite of ongoing certifications to demonstrate feasibility or infeasibility in §60.5393b.

4) Modification and reconstruction have never applied to such small ancillary equipment such as a single piston pump or diaphragm pump.

Therefore, the applicability date for pneumatic pumps under NSPS OOOOb should be the date of Supplemental Proposal.

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[82] Federal Register / Vol. 87, No. 233 / Tuesday, December 6, 2022 / Proposed Rules

8.2 Under NSPS OOOOb, we support the use of non-emitting pneumatic pumps for newly constructed well sites, tank batteries, and compressor stations, but we do not support the hierarchy of options proposed and inclusion of additional certification statements. The standard should be technology neutral similar to the pnuematic controller requirements.

The control options proposed for natural gas-driven pneumatic pumps are the same as those proposed to control natural gas-driven pneumatic controllers, yet the EPA is requiring additional technical demonstrations for pneumatic pumps that are not required for pneumatic controllers. We believe the requirements for natural gas-driven pneumatic pumps should be similar to those proposed for pneumatic controllers and the allowance for routing emissions to a control device which is allowed for pumps be extended to controllers (without any additional technical demonstration).

Furthermore, the hierarchal structure as proposed does not make logical sense as routing emissions to process, which has been a long-standing compliance option under the NSPS, is placed at a lower tier than that of implementing instrument air systems using solar or natural gas. As provided in Comment 12.9, the additional certifications associated with this hierarchy should be removed. The CAA already has provisions for knowing criminal violations related to false statements, which includes reference to false material statement, representation, or certification in/omits material information from/alters, conceals or fails to file or maintain a document filed or required to be maintained under the CAA.

8.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic pumps.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms ‘natural gas-driven pneumatic pump’ and ‘pneumatic pump’ interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic pumps. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric pumps as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(h)(1):

> *For the purposes of §60.5393b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic pumps at a site is increased by one or more.*

We offer the following suggested for modification redline to §60.5365b(h)(2):

> *For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic pumps in accordance with paragraph (h)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven pneumatic pumps at the site in accordance with paragraph (h)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (h)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (h)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic pumps is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of natural gas-driven pneumatic pumps”*

criterion in (h)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of natural gas-driven pneumatic pumps replaced exceeds 50 percent. For purposes of paragraphs (h)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of ~~component~~ natural gas-driven pneumatic pump replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic pump replacement.

(i) If the owner or operator applies the definition of reconstruction in §60.15, reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic pumps exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic pumps at the site. The "fixed capital cost of the new pneumatic pumps" includes the fixed capital cost of all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic pumps replaced, reconstruction occurs when greater than 50 percent of the pneumatic pumps at a site are replaced. The percentage includes all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]. If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic pumps that are replaced, the owner or operator must comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review also apply.

8.3.1 Additional clarifications are required for the proposed requirements for reconstruction of pneumatic pumps.

In review of the proposed regulatory text provided for §60.5365b(h)(2), the following elements of the proposed regulatory text require clarification:

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed.** Similar to natural gas-driven pneumatic controllers, the proposed language in §60.5365b(d)(2)(ii) suggests that reconstructed natural gas-driven pneumatic pumps would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic pumps. We believe it was EPA's intent to not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 proposal.

8.4 Suggested clarifications to certain proposed definitions related to pneumatic pumps in NSPS OOOOb and EG OOOOc.

While EPA expanded the applicability to include piston pumps, EPA did not include a definition for what a piston pump is or is not beyond the definition for natural gas diaphragm pump currently provided. Without this additional definition we request the following technical clarification as it applies to lean glycol circulation pumps. We do not believe it was EPA's intent to include these within the new zero-emitting provisions and historically EPA made it clear that this was not their intent to include these under NSPS OOOOa.

> ***Natural gas-driven diaphragm pump*** *means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a ~~diaphragm~~ pneumatic pump.*

8.5 The provisions included §60.5365b(h)(3) should also reference piston pumps.

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. We support EPA's retention of the provisions proposed in §60.5365b(h)(3) as these pumps will, by their very nature, result in very low and intermittent emissions. In the model plant analysis, the emissions for a single natural gas-driven piston pump is only 0.11 tpy VOC and 0.38 tpy methane. Temporarily used piston pumps would emit even less, which is why they have historically been exempt from the control standards. Such an exemption would be analogous to what also already been granted for temporary natural gas-driven diaphragm pneumatic pumps, and we believe it was EPA's intent to also include piston pumps in this provision.

We offer the following suggested redline to §60.5365b(h)(3):

> *A single natural gas-driven diaphragm pump or piston pump that is in operation less than 90 days per calendar year is not part of an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year in accordance with §60.5420b(c)(15)(i) and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.*

8.6 Natural gas-driven pneumatic pumps in compliance with NSPS OOOOa

NSPS OOOOa requires certain diaphragm natural gas driven pumps to be routed to a control device or process. As such, these pumps are already controlled by at least 95%. EPA has not adequately considered or accounted for how to handle these existing controlled pneumatic pumps within the proposed rules. Specifically, these pumps should meet the requirements of EG OOOOc by continuing to comply with NSPS OOOOa. These pumps should also be excluded from modification and reconstruction under NSPS OOOOa.

8.7 EPA's Model Plant Analysis for Conversion to Electric, Solar or Instrument Air Pumps

EPA assumptions for converting pneumatic pumps to zero-emitting has a distinctly separate set of cost assumptions from the pneumatic controllers even though the same technologies are being proposed for use. While EPA relied on costs from the 2016 and 2021 Carbon Limits report for pneumatic controllers, EPA uses different costs and assumptions as it pertains to converting to electric (assumed to be grid power) and solar pumps, which are not well documented and appear based on old information dating back to 2012. The EPA's economic feasibility analysis for pneumatic pumps presented in file "Supplemental TSD Ch 4 Pneumatic Pump.xlsx" are also only adjusted to 2019 USD from 2012 dollars. Thus, values presented are underestimated by at least 14%.[83]

9.0 Well Liquids Unloading Operations

As we communicated to EPA in our January 31, 2022 letter[84], well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective because there are numerous misconceptions about why and how this activity is conducted. While we support EPA's inclusion of well liquid unloading operations as an affected facility, the regulation should be based solely on the work practice standard outlined in §60.5376b(c)(2) and (d) and should not include a zero-emission limit as provided in §60.5376b(b). To this end, the recordkeeping and reporting requirements must be amended to be a workable framework for operators to assure compliance including removal of the certification statement by an engineer in every instance that venting may occur.

Lastly, the applicability for liquid unloading operations must be designated as the date of the Supplemental Proposal as the recordkeeping requirements were not explicitly known for each event that ocurred prior to the publication. Much of the recordkeeping elements proposed in the December 2022 proposal, including the certification statement by engineer, was not anticipated based on the descriptions in the November 2021 proposal.

9.1 Well liquid unloading operations should be subject to work practice standards and not held to a zero-emission limit.

API supports the proposed alternative measures outlined in §60.5376b(c)(2) and (d), which provide a clear and rational work practice standard based on Best Management Practices (BMPs) that achieve the intent to reduce

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[83] https://www.usinflationcalculator.com/

[84] EPA-HQ-OAR-2021-0317-0808

emissions from liquid unloading of gas wells. These provisions should be considered BSER and should not be considered an exception to the standard as currently proposed in §60.5376b(c).

We appreciate EPA's recognition that solely imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations that in many situations could severely halt natural gas production. For some situations, a certain unloading technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. The work practice standards proposed in §60.5376b(d) allow operators the flexibility needed to minimize emissions from well liquid unloading, while allowing for unexpected situations or outcomes that may occur during the unloading operation that might result in a minimal amount of emissions to be vented.

To be clear, while we support the work practice provisions in §60.5376b(c)(2) and (d), we do not support the provisions proposed in §60.5376b(b) establishing a zero-emission limit on liquid unloading operations as this limit creates undue burden of compliance when EPA has acknowledged it is known that not every liquid unloading operation can technically or safely meet the zero-emission limit. This undue burden is compounded when considering the logistical and practical implementation of the associated recordkeeping, reporting and certification statements also proposed. See also Comment 12.9.

9.2 Additional clarification to the proposed definition of liquids unloading is warranted.

As we previously commented in our January 31, 2022 letter, other well maintenance and workover activities may occur on a well that are distinctly different, require separate specialized equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. EPA must explicitly provide clarification to address these distinctions, within the definition for "liquids unloading" so not to confuse other activities that might occur at a well with the liquids unloading operation provisions as proposed.

Our suggested clarification to the definition of liquids unloading under §60.5430b and §60.5430c is as follows:

> *Liquids unloading means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production. Routine well maintenance activities, including workovers, screenouts, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.*

9.3 The recordkeeping and reporting for liquids unloading operations must be simplified into a manageable framework for operators and streamlined for liquid unloading operations that vent to atmosphere.

The information proposed by EPA within §60.5420b and §60.5420c for the recordkeeping and reporting as it pertains to liquid unloading operations is focused on an operator tracking and certifying techniques and less focused on allowing an operator to perform the necessary procedures to unload liquids accumulated within the wellbore and maintain natural gas production with as minimal emissions as possible. To address this shortfall, we suggest EPA define the data operators should track per unloading operation and remove all superfluous records that generate additional burden for the operator and EPA without added environmental benefit. These suggestions assume that liquid unloading operations are to be conducted using a work practice standard according to our suggestion in Comment 9.1.

The current proposed recordkeeping requirements do not offer a reasonable framework for operators to maintain compliance assurance. In fact, EPA has included a certification by professional engineer for every instance a well unloading operation vents emissions to atmosphere in §60.5420b(c)(2)(ii)(B) and §60.5420b(b)(3)(ii)(B) based on the proposed zero emissions limit standard. This may not be known to an operator until the liquid operation is taking place based on a variety of parameters. For context, a single well affected facility may undergo multiple liquid unloading operations in a single compliance period. For example, one well may necessitate an unloading schedule of four times in a year. Based on best management procedures, three (3) of these events may occur with zero emissions, while one (1) of the events might vent to atmosphere for a short duration using the same technique. The justification provisions in §60.5420b(c)(2)(ii)(B) are untenable when the same technique used on a well may resulted in zero emissions during some liquid operations, but not during all liquid unloading operations in the same compliance period. The fact is that in some instances a well liquid unloading operation may need to vent emissions for short duration, sometimes a little as 30 minutes, to safely perform the liquid unloading operation. We therefore request:

1) EPA remove the additional engineering certification statements under the guise of technical demonstrations. These additional certifications would be unnecessary if the standard followed a work practice procedure (see Comment 9.1).

2) Limit recordkeeping and reporting to liquid unloading operations that result in emissions only. This would reduce the administrative burden for thousands of liquid unloading operation events. This is also consistent with how both Colorado and New Mexico have organized recordkeeping and reporting for their state regulations.

   Our suggestions to streamline and simplify the recordkeeping and reporting for liquid unloading operations is as follows:

   > *For each gas well affected facility that conducts liquids unloading operations during the reporting period that resulted in emissions vented to the atmosphere:*
   >
   > - *US Well ID*
   > - *The number of liquids unloading events during the year that resulted in emissions.*
   > - *The date and time of each liquid unloading operation where venting occurred.*
   > - *The duration of venting in hours.*
   > - *Reason venting occurred*

Additional recordkeeping for liquid unloading operations should include:

> *Documentation of your best management practice plan developed under paragraph §60.5376b(d). You may update your best management practice plan to include additional steps which meet the criteria in §60.5376b(d).*

10.0 Compressors

API endorses the comments being submitted by GPA Midstream Association as it pertains to reciprocating and centrifugal compressors and provides the following additional comments.

10.1 Reciprocating and Centrifugal Compressors should be subject to a work practice standards with clear repair and delay of repair provisons instead of an emission standard.

Within Section IV.I.of the preamble (87 FR 74796), the EPA acknowledges *"over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder."* EPA also provides its rationale for the proposed level of excessive leaking (87 FR 747996) as "*the 2 scfm flow rate threshold was established based on manufacturer guidelines indicating that a flow rate of 2 scfm or greater was considered indicative of rod packing failure."* In summary, the EPA anticipates emissions from rod packings over time even from reciprocating compressors that are properly operated and maintained.

Yet, at the same time, EPA proposes to establish the 2 scfm flowrate as a not-to-exceed standard of performance, such that a violation occurs if flow rate exceeds that value (87 FR 74797). In doing so, EPA fundamentally misconstrues the manufacturers recommendations. In practice, exceeding a manufacturer-recommended flow rate is an indication that a repair should be made. Exceeding that rate does not necessarily compromise operability of the unit and, in fact, the values are selected to allow continued operation for the period necessary to arrange for needed repairs to be made. EPA without explanation proposes to transform what in practice constitutes an action level into a regulatory cap that cannot be exceeded without the prospect of incurring a violation. EPA's proposal is at odds with the facts and is an unreasonable reinterpretation of standard maintenance practices.

Therefore, if EPA is intent on setting a numeric standard of performance, the value must be well above the 2 scfm that EPA believes to be the standard manufacturer recommendations. The value must accommodate operations for a reasonable and potentially significant period of time that may be needed to accomplish needed repairs. If EPA takes this path, a reproposal is necessary so that we can know the newly proposed value, understand EPA's rationale, and have an opportunity to submit comments on the record. Alternatively, we believe that the flowrate can be established as a work practice that would trigger a repair obligation rather than constitute a numeric emissions limitation. While it is true that flow can be measured here, it is not technically or economically practicable to install measurement systems that would assure complliance with a numeric emissions limitation. See CAA § 111(h)(2)(B).

10.2 Clarification is required for compressors with multiple cylinders or seals.

In the November 2021 preamble (86 FR 63216), EPA described the rod packing requirements as follows:

> *"We are proposing that BSER is to replace the rod packing when, based on annual flow rate measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. We are proposing that if annual flow rate monitoring indicates a flow rate for any individual cylinder as exceeding 2 scfm, an owner or operator would be required to replace the rod packing."*

In looking at documentation for the dry seal proposed requirements, the Natural Gas Star[85] report where this value was seemingly derived, it is stated, "*During normal operation, dry seals leak at a rate of 0.5 to 3 scfm across each seal (1-6 scfm for a two seal system), depending on the size of the seal and operating pressure…. An example of one type of tandem seal with leak rates ranging between 0.5 to 3 scfm for 1.5 to 10 inch compressor shafts, for compressors operating at 580 to 1,300 psig pressure.*"

In the proposed text provided in §60.5380b or §60.5385b(a), the distinction that the limits are per cylinder or seal is unclear. It would be impratcical for a compressor with multiple cyclinders (reciprocating) or seals (centrifugal) to operate the same as compressor with only a single cyclinder or seal. As the Natural Gas star report documents, it is also impractical to expect the same level of emissions from dry seals for various sized units.

Therefore, EPA must clarify that the emission threshold designated is by cylinder or throw (reciprocating) and per seal (centrifugal). We note that the following suggested redlines for NSPS OOOOb and EG OOOOc are consistent with §95668 (c)(4)(D) of the 2017 California's GHG Emissions Regulations, which this proposed standard was based:

> *§60.5385b(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5393c(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5380b(a)(4)(i): The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section.*
>
> *§60.5392c(a)(1): You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. The volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm.*

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[85] https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/ll_wetseals.pdf

10.3 Conducting annual measurements on temporary compressors is logistically impractical and temporary compressors should be exempt from §60.5365b(b) and (c)(b).

Temporary compressors should be exempt from the monitoring requirments as it would be infeasible to conduct monitoring on a compresor that will be removed from a site after less than a year. Equipment that is intended for temporary use and is not a stantionary source should not not be subject to either NSPS OOOOb and EG OOOOc. API requests EPA make the following clarifications to address this concern:

> *§60.5365b(b): Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart. A centrifugal compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*
>
> *§60.5365b(c): Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart. A reciprocating compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*

10.4 Reciprocating Compressors

While API supports certain aspects of the Supplemental Proposal for reciprocating compressors, addiitonal clarifications must be made. The following amendments, in addition to the items outlined above and in comments submitted by GPA Midstream Association, would alleviate some of the significant technical cocnerns our members have with the proposed requirements.

- **Emissions from reciprocating rod packing vents that are routed to a process or flare should be considered an adequate alternative in reducing emissions.** EPA should continue to allow an option for rod packing vents to be routed to a control device for new, modified and existing facilities. The incremental benefit achieved between monitoring and subsequent repair (if applicable) versus capturing the vent to control device that achieves 95% destruction efficiency has not been substantiated by EPA within their cost benefit analysis. This is especially true for any compressor that already is designed and configured to route rod packing to a flare or other combustion device.

- **EPA should provide additional flexibility for addressing rod packing leaks by allowing operators to forgo annual emission measurements and replace rod packing annually.** Given the sheer number of compressors that will apply to NSPS OOOOb and EG OOOOc, EPA should provide flexibility by allowing operators the option to change out rod packing annually or 8760 hours (whichever comes first), which is similar in approach but more frequent than the current requirements in NSPS OOOO and OOOOa, or to perform the newly proposed annual monitoring and replacement of rod packing if emissions exceed to specific threshold as identified.

- **Repair parameters were omitted from the proposed regulatory text.** The EPA states their intent to define some repair parameters for reciprocating compressors in the preamble (87 FR 74798):

  > *"The proposed NSPS OOOOb regulatory text also specifies that flow rate monitoring be conducted in operating or standby pressurized mode, and "repair" and "delay of repair" schedules, in addition to other clarifying requirements. The EPA is proposing to require conducting flow rate measurements during operating or standby pressurized mode because the measured emissions would be representative of actual emissions during operations. Repair schedules are proposed to require repair of equipment in a timely manner to mitigate emissions. Delay of repair would be allowed when owners and operators required more time to repair equipment based on scenarios beyond the owner or operator's control (e.g., issues with availability of equipment or where repair necessitates a compressor shutdown when redundancy of compressors is not available)."*

  However, the repair and delay of repair schedules could not be located in the proposed regulatory text. As stated in Comment 10.1, the EPA should establish a monitoring schedule for reciprocating compressors with reasonable repair times. Further, allowances should be incorporated to address situations that delay repairs, appropriately.

  California regulations governing rod packing emissions, upon which these proposed regulations are based, require repair within 30 calendar days from the date of the initial emission flow rate measurement. Furthermore, repair of a compressor typically cannot be performed while the compressor is in service, and some situations may arise that warrant delay of repair. We therefore request EPA amend the provisions in §60.5380b and §60.5385b to accommodate a work practice standard that includes clear provisions for repair or replacement and delay of repair or replacement that is consistent with §60.5397b(h)(3).

10.5 Centrifigal Compressors

10.5.1 Clarification is requested to the definition of centrifugal compressor.

Within the definition "centrifugal compressor" in §60.5430b and §60.5430c, EPA describes the compressor as "*discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers."* The phrasing of "significantly higher-pressure" should be further delineated to eliminate ambiguity. If left undefined the regulated operator does not have a clear understanding of what is affected and what is not affected.

The definition of centrifugal compressor as it was used in the initial NSPS OOOO rulemaking only affected wet-seal centrifugal compressors, which includes a relatively small population of affected facilities that were generally considered to discharge significantly higher-pressure natural gas. With the expansion of the NSPS OOOOb and EG OOOOc to also include dry seal compressors, which are more widely utilized, additional clarity is warranted.

In the oil and natural gas industry, compressors that boost natural gas pressures are normally designed to discharge natural gas greater than 300 pounds per square inch differential (psid). The original intent of EPA including this language was to exclude smaller compressors with low differential pressure (e.g., process compressors, vapor recovery units, and other low pressure service units). With this consideration, API recommends that EPA update §60.5430b to include a definition of significantly higher-pressure and includes the following language:

> *Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart. For the purposes of §60.5380b, significantly higher-pressure means having a design pressure differential greater than 300 pounds per square inch differential (psid).*

10.5.2 The emission limit for dry seal compressors should properly account for compressor size.

The origin of and basis for the proposed three (3) scfm limit for dry seal compressors is not provided within the EPA docket and associated references. API suspects that the genesis of this number did not consider variable compressor sizes, resulting in a low value for the standard that is not representative of all operations. In Section IV.G.1.b.iii of the Federal Register, the origin of this value is as follows: *"The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in §95668(d)(4-9), California's Regulations*[86] *for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate*[87]*."* Research into the underlying sources of the CARB regulation does not yield supporting information for the development of the 3 scfm standard. EPA should supplement the docket with information to support why this value is representative of the population of dry seal compressors across the nation (taking into consideration compressor size variability).

Larger compressors usually have larger shaft diameters, higher operating speeds, and greater operating pressures. These three variables all contribute factors to the amount of gas that might ultimately slip through the seals. The combination of these three factors will usually yield higher leak rates from seals as measured on a volumetric basis, thus larger compressors will have a higher baseline for normal operations.

Based on data submitted to the EPA pursuant to 40 CFR Part 98, Subpart W for the 2021 calendar year, dry seal compressor driver power output ranged between 5 – 42,000 horsepower and for wet seals the compressor driver power output ranged between 40 – 53,665 horsepower.[88] We do not believe compressors associated with the higher end of this range should be expected to operate the same as compressors closer to the lower end of this range. Table 2provides more details on our short analysis showing variable sizes of both dry and wet seal compressors as reference.

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[86] https://ww2.arb.ca.gov/sites/default/files/2020-03/2017 Final Reg Orders GHG Emission Standards.pdf

[87] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf, page 100.

[88] Information was extracted from EPA's Envirofacts database using the GHG query builder: https://enviro.epa.gov/query-builder/ghg.

Table 2. Variation in Compressor Driver Output as Reported under EPA's Greenhouse Gas Reporting Program for Calendar Year 2021

Compressor Horsepower Driver Details as reported to EPA for Calendar Year 2021	Count of Compressors in Dataset	Compressor driver power output (Horsepower)		
		Average	Minimum	Maximum
Dry Seals				
Onshore natural gas processing	310	6,427	5	38,000
Onshore natural gas transmission compression	812	14,431	144	42,000
Underground natural gas storage	19	9,817	5,700	15,280
Wet Seals				
Onshore natural gas processing	199	9,426	40	53,665
Onshore natural gas transmission compression	345	5,027	990	30,000
Underground natural gas storage	22	3,910	1,275	9,800

10.5.3 Additional clarification is needed regarding the volumetric flow.

Both wet seal and dry seal systems often use an inert gas, such as nitrogen, for system blankets at positive pressure. That nitrogen vents through the same vent as the seal gas. So measured total vent rates may be overestimating the amount of methane or VOC being vented to atmosphere. Actual vent rates of methane and VOC could be under the standard, but the total volumetric flow could be over due to the nitrogen blanket. EPA should make clear that the standard could be interpreted as either total volumetric flow or methane and VOC flow depending on which method of monitoring is employed.

EPA should also expand the volumetric flow measurement options to allow for alternative ways to obtain the methane and VOC flow:

- Use of thermal mass meter or ultrasonic meter readings in conjunction with gas composition samples to calculate methane and VOC flow, or
- Flow balance equations (i.e., if the amount of inert gas into the system is metered, then that volume could be subtracted from the total flow measurement, thus yielding the methane and VOC only flow.)

10.5.4 The wet seal centrifugal compressor requirements must be clarified between NSPS OOOOb and EG OOOOc.

It is unclear why the standards between NSPS OOOOb and EG OOOOc for centrifugal compressor standards are different:

- NSPS OOOOb – Dry seal compressors and "self-contained wet seal compressors" can only comply with volumetric standard. All other wet seal compressors can only comply with the 95% capture and control requirement.
- EG OOOOc – Any wet seal compressor can either comply with volumetric standard or reduce emissions by 95% through a control standard.

The implications of the NSPS OOOOb regulations seem to be that the 3 scfm volumetric standard is equivalent to the 95% capture and control requirement. If this is the case, then it stands to reason that all centrifugal

compressors should be able to choose to comply with either the volumetric standard or the 95% capture and control practice.

If owners of centrifugal compressors had the option to comply with either standard, it obviates the need for a specially defined class of compressors: "Self-contained wet seal compressors." Removing this definition from the rule would result in a more simple and straightforward understanding of the rule requirements. API proposes the NSPS OOOOb standards mimic the EG OOOOc standards.

10.5.5 The proposed requirements for Wet Seal Centrifugal Compressors do not consider our previous comments regarding the unique equipment design in the Alaskan North Slope.

On the Alaska North Slope (ANS) there is not a market for natural gas sales. Most of the gas that is produced with the oil is separated and either used as a fuel or is compressed (using large wet seal compressors) to be reinjected back down hole for gas lift or enhanced oil recovery. The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.

Wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures most of the gas by volume then routes that gas to a flare, as described in our January 31, 2022 comment letter[89]. The ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum / tank, where any remaining entrained gas breaks out and is vented to atmosphere. In 2010, EPA's Natural Gas Star[90,91] program, in conjunction with BP, conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis concluded that the sour seal oil degassing design employed on the ANS has greater than 99% emission control by volume. This same study is also cited by the CARB regulations references. It would stand to reason that this system of gas capture and control should be allowable to use the volumetric standard.

In summary, wet seal compressors with the sour seal oil traps in Alaska as described above, route the gas to the flare, not to the "compressor suction." Because of this, these compressors would seemingly not meet the definition of "self-contained wet seal compressor." However, there is language in that definition which suggests that the purpose of that definition is that degassed emissions do not route to atmosphere as proposed in §60.5430b and §60.5430c (***emphasis added***). Therefore, API offers the following redline for the definition of self-contained wet seal centrifugal compressor:

> *Self-contained wet seal centrifugal compressor means a wet seal centrifugal compressor system which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to either another process or combustion device ~~that is a closed process that ports the degassing emissions to the natural gas line at the compressor suction~~ (**i.e., degassed emissions are recovered**). The de-gas emissions are routed back to ~~suction~~ a process or combustion device directly from the intermediate closed degassing process ~~degassing/sparging chambers~~; after the intermediate closed process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.*

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[89] EPA-HQ-OAR-2021-0317-0808

[90] https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf

[91] https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf

Alternatively, as outlined in Comment 10.5.4, EPA could allow all centrifugal compressors the option to comply with the volumetric standard thereby obviating the need for a special definition for a “self-contained wet seal compressor.”

11.0 Leak Detection and Repair at Gas Processing Plants

API supports EPA’s proposal for bimonthly OGI monitoring for equipment leaks at gas processing plants. We also support incorporation of NSPS Vva into NSPS OOOOb and EG OOOOc as an alternative monitoring option with the additional simplifications EPA has proposed. While API also generally supports the use of Appendix K for OGI monitoring at gas processing plants, we have several comments with respect to proposed Appendix K as provided in Attachment A, which are in direct response to EPA’s solicitations within the preamble.

In addition to the above items, API offers the following comments concerning leak detection and repair requirements at gas processing plants.

11.1 Closed vent systems should be monitored annually using OGI or Method 21.

EPA is proposing initial and bi-monthly OGI or quarterly Method 21 monitoring of closed vent systems which are increased monitoring frequencies when compared with the existing annual Method 21 monitoring under NSPS OOOO, NSPS OOOOa, NSPS Vva, and other LDAR regulations. API’s previous comments on this topic[92] were intended to voice support for the use of OGI in monitoring closed vent systems and did not fully consider the implications and minimal environmental benefits of more frequent monitoring.

Closed vent systems have historically been subject only to initial and annual inspections due to their low leak rates. Closed vent systems rarely leak because of the small number of components and lack of constantly moving parts. The hard piping or ductwork in closed vent system do not experience the same wear and tear and potential for leaks as moving parts that generate friction. While OGI does not have the same proximity challenges as Method 21, more frequent monitoring of closed vent systems would still be impractical for both methods as parts of closed vent systems are considered difficult to monitor. More frequent inspections for closed vent systems at gas plants under NSPS OOOOb and EG OOOOc would also be more stringent than the requirements for refineries and chemical plants. Therefore, API recommends that for closed vent systems, hard piping be subject to an initial Method 21 or OGI inspection and annual AVO inspections and ductwork be subject to an initial Method 21 or OGI inspection and annual Method 21 or OGI inspections. If EPA decides to finalize the increased monitoring frequency for closed vent systems, they must provide additional justification including the additional environmental benefits expected from more frequent monitoring of equipment that rarely leak.

Emissions detected from closed vent systems do not constitute a violation of the “no identifiable emissions” standard provided work practice standards are fully implemented. See Comment 5.1 for a more detailed discussion.

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[92] EPA-HQ-OAR-2021-0317-0808

11.2 The lack of a VOC or methane concentration threshold expands monitoring requirements with minimal, if any, environmental benefit.

As API noted in its prior comments[93], EPA should retain the current 10 percent by weight threshold for VOC and propose a similar concentration threshold for methane, which we suggested as 1 percent by weight threshold for methane. In the Supplemental Proposal, EPA is proposing that monitoring apply to each piece of equipment "that has the potential to emit methane or VOC", which is effectively a zero-applicability threshold for both methane and VOC.

Some streams at gas processing plants contain methane or VOC but in such low concentrations that monitoring would be meaningless as it would likely always result in no detected emissions. Examples of such streams include but are not limited to purity ethane, acid gas, ancillary chemicals, wastewater, and recycled water. The proposed monitoring of additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with minimal, if any, environmental benefit.

In its existing LDAR regulations, EPA has recognized and reaffirmed the need for concentration thresholds to achieve cost-effective emission reductions. The agency has not provided sufficient justification for deviating from this longstanding practice with this rulemaking. Based on an initial review of EPA's TSD[94] from the November 2021 Proposal, API notes the following about EPA's analysis:

- EPA considers only components in VOC service and non-VOC service, which the agency appears to define as follows:

> *"In VOC service" is defined as a component containing or in contact with a process fluid that is at least 10 percent VOC by weight or a component "in wet gas service", which is a component containing or in contact with field gas before extraction. "In non-VOC service" is defined as a component in methane service (at least 10% methane) that is not also in VOC service.*

- EPA estimates VOC and methane emissions and therefore emission reductions and cost-effectiveness using only the following composition ratios identified in Table 10-8 of the TSD:

Component Service	Methane: TOC	VOC: TOC
VOC Service	0.695	0.1930
Non-VOC Service	0.908	0.0251

- EPA appears to treat the "potential to emit to methane" as equivalent to "in non-VOC service" in evaluating control options:

> *In addition to selecting one of the LDAR programs above, the EPA considered which components would be subject to the LDAR program. The current NSPS applies to components in VOC service (Option A). The EPA considered expanding the applicability to include components that have a potential to emit methane, which would add the components classified in this document as non-VOC service components (Option B).*

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[93] EPA-HQ-OAR-2021-0317-0808

[94] EPA-HQ-OAR-2021-0317-0166

Therefore, EPA does not appear to fully consider the cost-effectiveness of a potential to emit applicability threshold. API reiterates that EPA should retain the current 10 percent by weight threshold for VOC and establish a similar concentration threshold for methane (suggested as 1 percent by weight). Refer also to Attachment A.

In Comment 11.3, API offers recommended redlines to address this concern. Regarding how to determine when a piece of equipment is not subject to monitoring, the language in §60.5400b(a)(2) should also be revised as appropriate.

11.3 EPA should clarify which equipment is included in the evaluation of capital expenditure.

The definition of equipment is unclear on which equipment is considered when evaluating whether a capital expenditure occurred because capital expenditure is a definition, not a standard or requirement. This lack of clarity could lead to varying interpretations and uncertainty on whether a capital expenditure occurred. For other regulations, EPA has clarified the scope of equipment considered for the affected facility[95]. For leak detection and repair, an appropriate scope would be to apply the same definition of equipment to the capital expenditure evaluation as the standards and requirements. Therefore, the definition of equipment should clearly specify it also applies to capital expenditure.

To address this and the previous comment, API offers the following recommended redlines to definitions in §60.5430b.

> *Equipment, as used in the standards and requirements and for purposes of evaluating capital expenditure in section 60.5365b(f)(1) of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector ~~that has the potential to emit~~ in methane or VOC service and any device or system required by those same standards and requirements of this subpart.*
>
> *In methane service means that the piece of equipment contains or contacts a process fluid that is at least 1 percent methane by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in methane service.)*
>
> *In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in VOC service.)*

12.0 Overarching Legal Issues

12.1 The new source trigger date should be December 6, 2022, the date the Supplemental Proposal was published in the Federal Register.

In a memorandum associated with the Supplemental Proposal, EPA "solicits comments on whether CAA § 111(a) provides EPA discretion to define 'new sources' based on the publication date of the Supplemental Proposal and,

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[95] U.S. EPA Applicability Determination Index Control Number: 0600027, Modification and Capital Expenditure Calculations, dated February 9, 2001.

if so, whether there are any unique circumstances here that would warrant exercising of such discretion in this rulemaking by the EPA."

API believes that not only does CAA § 111(a) allow EPA to define the new source trigger date based on the publication date of the Supplemental Proposal, but also in fact requires it. Further, as API provides below, there are significant circumstances here that would warrant EPA altering the new source trigger date to December 6, 2022.

As explained in our January 31, 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) on the original NSPS OOOOb and EG OOOOc proposed rule, the original proposal was fundamentally incomplete because no proposed regulatory text was published or otherwise made available at the time of proposal. As a result, that proposal could not serve to set the new source trigger date for new requirements described in the proposed rule.

In the Supplemental Proposal, EPA reasserted that, except for newly proposed standards in the Supplemental Proposal (such as the standards for dry seal centrifugal compressors), the new source trigger date will be the date the original proposal was published in the Federal Register. EPA explains that "CAA Section 307(d)(3) specifies the information that a proposed rule under the CAA must contain, such as a statement of basis, supporting data, and major legal and policy considerations; the list of required information does not include proposed regulatory text." (87 Federal Register (FR) R 74716).

EPA further explains that "the Administrative Procedures Act (APA), which governs most Federal rulemaking, does not require publication of the proposed regulatory text in the Federal Register" and instead specifies that "notice of proposed rulemaking shall include ''*either* the terms or substance of the proposed rule *or* a description of the subjects and issues involved.'' (Emphasis added)." *Id*. EPA concludes that "the APA clearly provides flexibility to describe the ''subjects and issues involved'' as an alternative to inclusion of the ''terms or substance'' of the proposed rule." *Id*.

As an initial matter, EPA's analysis on this point indicates that EPA believes the CAA and the APA provide the flexibility to select November 15, 2021 as the trigger date for new sources, but nothing in EPA's analysis specifically concludes or determines that it must use the November 15, 2021 date. API believes that EPA's rationale for using November 15, 2021 remains flawed for three reasons. The lack of regulatory text (which was neither in the Federal Register notice nor otherwise made available in the docket prior to the close of the comment period) prevents the original proposal from setting the new source trigger date.

First, the CAA § 111(a)(2) definition of "new source" uses the term "proposed *regulations*" in defining the new source trigger date. As we explained in our comments on the original proposal, a preamble unaccompanied by regulatory text is not a "regulation." Here, the preamble to the original proposal was simply a description of the proposed regulations, but by itself did not constitute a proposed regulation because nothing in the preamble was intended by the Agency to constitute an enforceable legal obligation. And it could not, as EPA co-proposed multiple concepts for singular facility types in the November 2021 proposal and requested comment that informed the November 2022 Supplemental Proposal's regulatory text.

For example, in the November 2021 proposal, EPA co-proposed quarterly and semi-annual fugitive emissions surveys for well sites with baseline emissions of 3 or more and less than 8 tons per year of methane. EPA then abandoned the baseline emissions approach in the November 2022 Supplemental Proposal in favor of an equipment threshold. In another example, EPA co-proposed to define affected well facilities in two ways for purposes of the liquids unloading standards. Under one approach, every well that undergoes liquids unloading would be an affected facility; under the other approach, the affected facility would be limited to wells that

undergo liquids unloading that is not designed to eliminate venting. These co-proposals, while limited to a subset of the affected facilities, evidence that EPA intended the November 2021 proposal to be conceptual and a means of informing the November 2022 regulatory text.

The November 2022 proposal is complex and requires affected facilities to parse complicated standards that will inform significant capital expenditures and expensive compliance programs. Given the ultimate complexity of the November 2022 regulatory text and scope of impact, the November 2021 proposal's conceptual offerings did not put the regulated community on notice of the "regulations" in any meaningful way that could inform billions of dollars in capital expenditures and compliance program development. Instead, the regulatory text made available in conjunction with the Supplemental Proposal comprises the proposed regulation because that regulatory text defines the enforceable legal obligations that EPA proposes to impose under this rule.

Thus, even if the original proposal may have satisfied the nominal procedural requirements specified by CAA § 307(d) and APA § 553(b) (which it does not for the reasons explained below), the original proposal was not a proposed "regulation" for purposes of setting the new source trigger date under CAA § 111(a)(2). This is particularly true in light of the clear purpose of CAA § 111(a)(2), which is to put affected facilities that are constructed, reconstructed, or modified after the date of a proposed regulation on notice of the requirements that will apply to those facilities upon the effective date of the final regulation. The absence of proposed regulatory text in the original proposal prevents such affected facilities from knowing with reasonable certainty the precise requirements that might actually apply, and thus prevents them from adequately planning for compliance.

Second, EPA's interpretation of CAA § 307(d) and APA § 553(b) is unreasonable and does not make sense in the broader context of these provisions. For example, EPA argues that the required content of a proposed rule specified in CAA § 307(d)(3) does not expressly require regulatory text, but the corresponding content requirements for a final rule (specified in CAA §§ 307(d)(4)(B)(i), (6)(A), and (6)(B)) similarly do not expressly require regulatory text. By EPA's reasoning, that means that the Agency is not required to provide regulatory text as part of a final rule. That is nonsensical. This is particularly true because the record for judicial review is limited to the materials prescribed by CAA §§ 307(d)(3), (d)(4)(B)(i), (6)(A), and (6)(B). CAA § 307(d)(7)(A). If proposed and final rules do not need to include regulatory text, then regulatory text would not be subject to judicial review. That is contrary to reason and the clear intent of the law.

In short, it is simply not plausible to argue that because CAA § 307(d) does not expressly require a proposed rule to include regulatory text; EPA is not required to make proposed regulatory text available at the time of the 2021 "proposal". When considered as a whole, CAA § 307(d) plainly requires rule text to be available.[96]

Third, and more broadly, EPA and the Biden administration made a political judgment to rush issuance of the original proposed rule because the rule constitutes a prominent plank of the administration's climate change regulatory agenda, and it was deemed expedient to issue the proposed rule in conjunction with the 2021 Conference of the Parties to the United Nations Framework Convention on Climate Change in Glasgow, Scotland.[97] The fact that EPA acknowledged the original proposal would require a Supplemental Proposal with

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[96] EPA cites *Rybachek v. USEPA*, 904 F.2d 1276, 1297 (9th Cir. 1990) as supporting its position that proposed regulatory text is not necessary. That case is inapposite because the court relies on APA § 553(b)(3). While that provision applies to this rulemaking, the more specific requirements of CAA § 307(d) control here.

[97] EPA's press release for the original proposal is available at U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health | US EPA (""As global leaders convene at this pivotal moment in Glasgow for COP26, it is now abundantly clear that America is back and leading by example in confronting the climate crisis with bold ambition," said EPA Administrator Michael S. Regan**.** "With this historic action, EPA is addressing existing sources

actual regulatory text is plain evidence of the rush. The sheer size of the Supplemental Proposal – 146 pages in the Federal Register, *without* regulatory text (which is provided in the docket) – is further mute evidence of the incomplete nature of the original proposal.

We recognize that every administration has the right to set and implement its regulatory agenda. However, this Administration's desire to expedite issuance of the original proposed rule led to compromises in the usual regulatory procedures, including the decision not to make proposed regulatory text available. It would be unreasonable for affected facilities to bear the burden of those compromises. It is also arbitrary and capricious for EPA to decide to issue an admittedly incomplete proposed rule to satisfy political objectives, and, at the same time, assert that it is somehow complete enough to constitute a "proposed rule" that sets the new source trigger date.

As shown in the analysis above, nothing allows or requires EPA to utilize the November 15, 2021 date. Further, the failure of EPA to provide regulatory text in the November 15, 2021 proposal is reason enough for EPA to "warrant exercising" any discretion it does have with respect to the deadline.

Further, by utilizing November 15, 2021 as the relevant demarcation date, EPA will be including a significant number of sources that were new, modified, or reconstructed between November 15, 2021 and December 6, 2022. For a significant number of the affected facilities, operators will be required to retrofit those new, modified or reconstructed sources to comply with the regulations, including regulations not known to operators at the time of construction, modification or reconstruction. Many of these requirements involve either: (1) substantial capital expenditures for equipment (e.g., instrument air skids and/or generators for use of non-emitting pneumatic controllers); (2) engineering design (e.g., storage tanks, design for any covers and closed vent systems, among others); (3) acquisition (along with all other operators) of a substantial number of part and equipment (e.g., flow meters, calorimeters; and (4) substantial in-field resources for retrofits. Not knowing with reasonable certainty what the final rule would require would significantly complicate implementation of compliance measures, cause the rule to be much more costly for such sources than EPA predicts, and frustrate the regulatory purpose of setting the new source trigger date at the date of proposal (which clearly is intended to provide reasonable notice of the ultimate requirements so that planning can be done at the time of construction, reconstruction, or modification.

In addition, since the onset of the COVID pandemic and continuing to this day, there have been substantial supply chain disruptions, difficulty with obtaining parts and equipment and difficulty with finding personnel (either consulting or for employment) that can assist with implementation of the rule. These supply chain and personnel issues will increase given the extensive nature and reach of NSPS OOOOb alone (given all the operators that will need to comply) – not even accounting for other recent regulatory developments at the state and federal level (e.g., BLM waste prevention rule, Colorado regulatory requirements, and New Mexico requirements – to name a few). EPA will compound this supply chain and personnel concern by maintaining November 15, 2021 as the new source trigger date. EPA's motivation is further obscured given the sources constructed, modified or reconstructed between November 15, 2021 and December 6, 2022 are potentially subject to NSPS OOOOa and may ultimately be subject to EG OOOOc. Thus, API believes that EPA not only has the discretion but the requirement to assign December 6, 2022 as the new source applicability date. Even if this were not required, there is ample basis for EPA to do so for all the reasons previously stated.

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from the oil and natural gas industry nationwide, in addition to updating rules for new sources, to ensure robust and lasting cuts in pollution across the country. By building on existing technologies and encouraging innovative new solutions, we are committed to a durable final rule that is anchored in science and the law, that protects communities living near oil and natural gas facilities, and that advances our nation's climate goals under the Paris Agreement."").

12.2 EPA's interest in promoting Environmental Justice is laudable, but EPA must be mindful of the Clean Air Act's boundaries in advancing these goals.

API explained in its comments on the original proposal that we support EPA's attention to potential Environmental Justice (EJ) issues and agree with EPA that the emissions standards prescribed by this rule will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The oil and natural gas industry's top priorities are protecting the public's health and safety – regardless of race, color, national origin, or income – and the environment. We strive to understand, discuss, and appropriately address community concerns with our operations. We are committed to supporting constructive interactions between industry, regulators, and surrounding communities/populations including those that may be disproportionately impacted.

Our comments also explained that, while API supports EPA's EJ goals, the Agency did not provide sufficient detail in the 2021 Proposal to allow API to comment in a meaningful way. EPA has provided additional clarity on two key EJ provisions in the Supplemental Proposal. They are addressed separately below.

12.2.1 Consideration of EJ Impacts in CAA § 111 Standard Setting

First, EPA proposes to require consideration of impacted communities when setting existing source emissions standards that take into consideration remaining useful life and other factors (RULOF). For example, if "a designated facility could be controlled at a certain cost threshold higher than required under the EPA's proposed revisions to the RULOF provision, and such control benefits the communities that would otherwise be adversely impacted by a less stringent standard, the state in accounting for RULOF could choose to use that cost threshold to apply a standard of performance." (87 FR 74824).

EPA believes that it has authority to prescribe such a requirement because "CAA section 111(d) does not specify what are the "other factors" that the EPA's regulations should permit a state to consider", and thus the Agency may "interpret[] this as providing discretion for the EPA to identify the appropriate factors and conditions under which the circumstance may be reasonably invoked in establishing a standard less stringent than the EG." *Id*.

EPA further explains that part of its responsibility in reviewing the adequacy of state CAA § 111(d) existing source emissions control programs is to "determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives." *Id*. "The EPA finds that a lack of consideration to [disparate health and environmental impacts] would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally." *Id*.

Lastly, EPA explains that the "requirement to consider the health and environmental impacts in any standard of performance taking into account RULOF is consistent with the definition of "standard of performance" in CAA section 111(a)(1)" which "requires EPA to take into account health and environmental impacts in determining the BSER." *Id*.

We applaud and support EPA's overall objective of addressing potential disparate impacts. But we are concerned that the Agency's proposal to require such impacts to be addressed when RULOF is considered in setting state standards is not legally supportable.

To begin, the term "other factors" is a generic term in and of itself. But as used in the context of CAA § 111(d), that term does not reasonably mean that EJ may be considered in standard setting. First, CAA § 111(d)(1) states that EPA's regulations "shall permit" states to consider RULOF in setting existing source emissions standards. This

language places responsibility on the states, in the first instance, to determine the "other factors" they deem relevant in setting standards upon consideration of RULOF. EPA's role is to review the state determination and not to preemptively specify what factors a state may or may not consider. If a state's identification and consideration of other factors is reasonable, then EPA cannot reject the state's determination on the grounds that EPA believes the term "other factors" should be given a different meaning. EPA's proposed approach is inconsistent with the role Congress intended the states to fulfill as part of the CAA's broader "cooperative federalism" scheme.

Second, the term "other factors" must be interpreted in context. By specifying that states may consider "remaining useful life," Congress indicated that source-specific factors are relevant to the states' determinations. Since the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term "other factors" must be construed in a similar light. This interpretation is particularly true given that "standards of performance" under CAA § 111(a)(1) are technology-based standards that reflect the best system of emissions reduction determined applicable to affected facilities. EPA's proposed interpretation of "other factors" is inconsistent with this source-specific, technology-based regulatory scheme.

Third, unlike other standards under the CAA, CAA § 111 does not require or allow for standards to be based on an assessment of impacts regarding health or the environment. Where the CAA confers such authority, it does so expressly and usually in a context where criteria exist to determine the adequacy of such standards. For example, CAA § 112(f) requires impacts to health and the environment to be considered in determining whether "MACT"[98]-based NESHAPs are adequately protective to health and the environment. The statute specifies that EPA must provide an "ample margin of safety," as defined in the Benzene Waste NESHAP. CAA § 112(f)(2)(A), (B). The Title I air quality program is also designed in this fashion – with the National Ambient Air Quality Standards (NAAQS) established as the benchmark for acceptable air quality and the guidepost for formulating appropriate state programs.

Here, CAA § 111 does not provide any indication that EPA must or may consider health or environmental impacts associated with air emissions from affected facilities in determining BSER and in setting emissions standards. For over 50 years, CAA § 111 has properly been construed as a technology-based program designed to prescribe standards based primarily on consideration of the best available technologies that are adequately demonstrated and not cost prohibitive. EPA's goals here are important but would require standards to be based on impacts analyses of air emissions from affected facilities – an approach that is not incorporated into the CAA § 111 standard setting process.

EPA also states that not considering impacts would be "antithetical to the public health and welfare goals of CAA Section 111(d) and the CAA generally." There is no doubt that protecting public health and welfare are overarching goals of the CAA. That aspiration does not in itself confer regulatory authority that is not otherwise prescribed by the statute. Congress carefully designed the regulatory tools it intends EPA to use to accomplish an adequate degree of protection to health and welfare. For the reasons explained above, CAA § 111(d) does not require or allow for consideration of health or environmental impacts in standard setting.

Lastly, EPA argues that considering EJ impacts in state standard setting "is consistent with the definition of "standard of performance" in CAA Section 111(a)(1)" and that states must consider such impacts "just as the EPA is statutorily required to take into account these factors in making its BSER determination." *Id*. at 74824. More specifically, EPA asserts that the definition of "standard of performance" "requires the EPA to take into account health and environmental impacts in determining the BSER." *Id*. We respectfully disagree, as there is no language

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in the CAA § 111(a)(1) definition of "standard of performance" that requires or allows health or environmental impacts associated with air emissions from affected facilities to be factored into standard setting.

As explained above, that definition requires standards of performance to primarily be based on technology and cost considerations. The only exception is that "nonair quality health and environmental impact[s] and energy requirements" also must be taken into account in setting standards of performance. CAA § 111(a)(1). The statute thus is clear that the only "health and environmental impacts" that may be considered in setting a standard of performance are ***nonair*** health and environmental impacts. That provision traditionally has been interpreted to require EPA to consider cross-media impacts (e.g., wastewater created by an air emissions scrubber) so as not to create a different environmental issue through technical requirements meant to address air quality. Because the analysis that EPA would require here would focus on air emissions impacts, it cannot be grounded in the requirement to consider ***nonair*** quality health and environmental impacts. Moreover, because the statute specifies that only nonair quality health and environmental impacts may be considered in standard setting, EPA is precluded from interpreting general language in CAA § 111(a)(1) or 111(d)(1) as somehow authorizing consideration of air quality-based health or environmental impacts.

For all of these reasons, EPA should reconsider the proposed requirement to require consideration of EJ impacts when states or EPA implement the RULOF provision.

12.2.2 Requirement that states provide for "meaningful engagement" in their CAA § 111(d) programs.

The Supplemental Proposal provides further details and additional explanation of the proposal to require states to provide for "meaningful engagement" as part of their CAA § 111(d) regulatory programs. According to EPA, "[t]he fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare" (87 FR 74827). As a result, EPA asserts that "a key consideration in the state's development of a state plan, in any significant plan revision, and in the EPA's development of a Federal plan pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare." *Id*. "A robust and meaningful public participation process during plan development is critical to ensuring that the full range of these impacts are understood and considered." *Id*.

The "meaningful engagement" requirement is grounded in the assertion that "a fundamental purpose of the Act's notice and public hearing requirements is for all affected members of the public, and not just a particular subset, to participate in pollution control planning processes that impact their health and welfare." *Id*. at 74828-9. In explaining the legal basis for this requirement, EPA states that "[g]iven the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, the EPA believes it is reasonable to require meaningful engagement as part of the state plan development public participation process in order to further these objectives." "Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations ''as are necessary to carry out [its] functions under [the CAA].'' The proposed meaningful engagement requirements would effectuate the EPA's function under CAA section 111(d) in prescribing a process under which states submit plans to implement the statutory directives of this section." *Id*. at 74829.

API supports full and fair public process in the development and implementation of CAA programs, including state CAA § 111(d) programs. All affected entities should have a reasonable opportunity to know about and participate in the development of regulations that affect their interests. In that light, we offer the following comments on the proposed "meaningful engagement" requirement.

First, CAA § 111(d) states only that EPA shall establish a "procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan." This requirement to establish a "procedure" for "submit[ting] … a plan" unambiguously is directed only at the review and approval process as between the states and EPA and is not directed at the plan development process that must be followed by the state. In other words, CAA § 111(d) directs EPA to emulate only some of the CAA § 110 requirements – not all of them.

Thus, CAA § 111(d) does not allow EPA to impose upon the states any measures related to the process by which they develop their plans. It only provides authority to set up a process by which EPA reviews and approves the adequacy of standards of performance and the measures adopted by the states to implement and enforce such standards.

Second, to the extent that a "reasonable notice" standard applies to the development of state plans under CAA § 111(d), it is the states' responsibility to ascertain what is reasonable – not EPA's. CAA § 111(d) is one of many CAA provisions where Congress intentionally split responsibility between EPA and the states. Indeed, under this "cooperative federalism" scheme, "air pollution control at its source is the primary responsibility of States and local governments." CAA § 101(a)(3). In the earliest days of the CAA, the U.S. Supreme Court confirmed that the CAA "gives the Agency no authority to question the wisdom of a State's choices of emission limitations" if the limitations accomplish the goals of the CAA. *Train v. NRDC*, 421 U.S. 60, 79 (1975).

Implicit in the notion of cooperative federalism is that states not only have wide latitude to determine appropriate emissions limitations, but also have similarly wide latitude in the legal and regulatory processes by which such limitations are established. Thus, to the degree a "reasonable notice" obligation is imposed upon the states by CAA § 111(d), the states have primary authority and responsibility to determine how to implement this requirement. While EPA has responsibility to review and approve state programs, it may not require states to follow what it believes to be the most reasonable notice procedures. Instead, EPA must approve any state notice requirements that are facially reasonable, even if those are not the procedures EPA itself would have selected.

Third, even if EPA has authority to define what constitutes "reasonable notice" during the development of state plans, the proposed "meaningful engagement" requirement goes beyond what EPA may reasonably require. To begin, the term "notice" unambiguously means notification of those with interest in the matter at hand. The proposed requirements to engage with particular groups in particular ways (e.g., states must seek to overcome "barriers to participation" by "pertinent stakeholders") and make targeted outreach go well beyond the nominal statutory obligation of notification. EPA may "think [its] approach makes for better policy, but policy considerations cannot create an ambiguity when the words on the page are clear." *SAS Institute Inc. v. Iancu*, 138 S. Ct. 1348, 1358 (2018). Congress has imposed no explicit requirements and stated no intent in CAA § 111 or anywhere else in the CAA related accomplishing any particular environmental justice goals or outcomes. The word "notice" cannot carry as much meaning as EPA believes it should.

As for CAA § 301, it has long been understood that that provision does not "provide [EPA] Carte blanche authority to promulgate any rules, on any matter relating to the Clean Air Act, in any manner that the [EPA] wishes." *North Carolina v. EPA*, 531 F. 3d 896, 922 (D.C. Cir. 2008) (internal quotes and citations omitted). Here, CAA § 301(a)(1) is inapplicable because creating a new category of procedural requirements is not "necessary" for the Administrator "to carry out his functions under this chapter." CAA § 301(a)(1). As noted above, EPA's intentions are commendable. But the proposed "meaningful engagement" procedures are not "necessary" as that term is used in CAA § 301.

Lastly, EPA's proposed "meaningful engagement" procedures are are not adequately clear and objective. As noted above, Congress has not spoken in the CAA to the issue of environmental justice. EPA and interested parties are without guidance as to whether the issue should be addressed under the CAA and, if so, how.[99] Moreover, EPA's criteria for determining the adequacy of state "meaningful engagement" efforts are vague and EPA's authority under its proposed rules to accept or deny a state's efforts is not bounded by any readily objectively discernable principles. For example, how does EPA determine the manner of required engagement with any particular stakeholders? How does EPA decide what constitutes an actionable "linguistic, cultural, institutional, geographic, [or] other barrier" and, where such barriers are determined to exist, whether the state's proposed approach is sufficient? What measures are needed for state programs to be adequately inclusive? These are all weighty questions that the statute does not expressly address and that EPA leaves fundamentally uncertain in its proposed rule. As a result, the proposed rule is vague, unmoored to the statute, and unless corrected, would be arbitrary and capricious. *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983).

For these reasons, "meaningful engagement" should be encouraged by EPA but cannot be a required element of approvable state CAA § 111(d) programs.

12.3 EPA does not explain the legal basis for its proposal to empower third parties to conduct remote monitoring that may trigger enforceable obligations by affected facilities.

In the original proposal, EPA presented a preliminary concept that would "take advantage of the opportunities presented by the increasing use of [advanced methane detection systems] to help identify and remediate large emission events (commonly known as "super-emitters")" (86 FR 63177). EPA sought comment on "how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event." *Id*.

As we explained at the time, API concurs with the importance of identifying and addressing large emissions events. Emissions from such events have the potential to be much greater than those from normal operations at a given facility. API shares EPA's interest in seeking to reduce the incidence of such large emissions events.

We noted in our comments that the proposed "Super Emitter Response Program" was unique in that it would be the first time under the CAA that EPA asserts authority to create regulatory obligations for affected facilities based on monitoring conducted by unaffiliated third parties. We further noted EPA did not explain the legal basis for establishing such a requirement and explained that an explanation from EPA was essential to understanding whether such a novel provision is legally viable.

Unfortunately, the Supplemental Proposal does not provide the needed explanation. That failure to explain the legal underpinnings of such a key element of the proposal violates the CAA § 307(d)(3)(C) requirement to include as part of the proposed rule "the major legal interpretations underlying the proposed rule." If not cured, it also would render the final rule arbitrary and capricious because EPA would have failed to address and explain a key factor underlying this aspect of the final rule.

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[99] It is notable that the 2022 "Inflation Reduction Act" included the most significant amendments to the CAA in decades and specifically targeted Environmental Justice concerns, yet Congress stopped short of amending CAA § 111 or the other existing substantive CAA programs to require or allow consideration of EJ. In other words, Congress expansively addressed EJ, but did so by providing copious funding to address the issue and chose not to create obligation or authority to otherwise address or consider EJ in implementing the existing CAA substantive programs.

To be sure, the Supplemental Proposal includes a lengthy discussion in the preamble called the "Statutory Basis of Super-Emitter Program" (87 FR 74752). For some four pages, EPA delves deeply into two explanations as to how it believes "the proposed super-emitter response program … fits within the EPA's authority under section 111 of the CAA." *Id*. In particular, EPA explains how the program might be justified by treating super-emitting events as an affected facility warranting a § 111 emissions standard and, alternatively, how the "super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule" (either as an added compliance assurance measure or as additional equipment leak work practices). *Id*. at 74752-4.

As for those suggestions, API disagrees with EPA's contention that it has authority to treat super-emitting events as an affected facility warranting a § 111 standard of performance. Rather, at most, EPA has the authority to consider identification of super-emitter events as "monitoring" for an affected facility. As such, super-emitters may only be regulated at facilities that already are subject to NSPS OOOOb or EG OOOOc for other reasons. In other words, if a thief hatch on an NSPS OOOOb storage vessel were left open, it could (if meeting the threshold – and subject to the legal concerns set forth below) be considered a super-emitter, and EPA could require corrective action to close the thief hatch. This would be similar for emissions above the threshold from an unlit flare or control device that is mandated by NSPS OOOOb or EG OOOOc (once applicable). However, a super-emitter cannot arise from equipment at a stationary source that is not already an affected facility.

In other words, if an aerial survey identified emissions from a thief hatch on a storage vessel that is not subject to NSPS OOOOb, and the storage vessel is not yet subject to EG OOOOc, then this cannot be a super-emitter affected facility subject to the regulations and for which an operator has to take corrective action. EPA's preamble appears to support this approach in several places, but does not specifically state this in the rule. Thus, as written, it appears that one could identify a super-emitter at a stationary source that has no affected facilities or from equipment that is not an affected facility. EPA has not justified that super-emitters – many of which are malfunctions – are or can be independently considered "affected facilities" under CAA § 111.

An in any event, nowhere in this lengthy discussion – nor in any other part of the preamble or supporting documents – does EPA explain where in the CAA it finds authority to empower third parties to submit monitoring information to an affected/designated facility that triggers regulatory obligations for the facility under the rule. The need for a legal explanation is particularly necessary here, given that this is the first time that EPA has sought to establish such a requirement under CAA § 111 or, to our knowledge, under the CAA as a whole.

We also note that EPA provides a lengthy discussion of the policy rationale that stands behind the proposed Super-Emitter Response Program, including an extensive explanation of how EPA believes that "[t]he design of the super-emitter response program ensures that the EPA will make all of the critical policy decisions and fully oversee the program." *Id*. at 74749-51. In EPA's view, "the qualified third party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications within the limited confines that EPA has authorized." *Id*. at 74750. Moreover, such notifications "originating from third parties would not represent the initiation of an enforcement action by the EPA or a delegated authority." These arguments indirectly speak to EPA's assertion of possible legal authority, but the policy rationale by itself cannot legally justify EPA's novel proposal to empower citizens to develop and submit information that triggers legal obligations for affected/designated facilities.

We lastly note that, in our comments on the original proposal, we explained that CAA § 304 expressly prescribes a role for citizens in CAA implementation by authorizing them to file civil lawsuits challenging alleged violations of, among other things, CAA § 111 emissions standards. We pointed out that Congress did not provide similar express

language in CAA § 111 or elsewhere in the CAA authorizing citizen monitoring as provided in the proposed super-emitter response program. In this context, the absence of such language should be construed as a limitation on EPA's authority to allow such monitoring and such an absence is not an implicit delegation of authority from Congress to EPA.

As a further note on the relevance of CAA § 304, that section prescribes strict criteria for obtaining injunctive relief to address alleged CAA violations – including prior notice, opportunity for the government to take the lead on an enforcement action, standing to bring an enforcement case, proof of liability, and sufficient rationale to support injunctive relief. The proposal runs counter to CAA § 304 by enabling citizens to obtain injunctive relief through the super-emitter response program (in this case, investigation, corrective action, root cause analysis, and related measures) without satisfying the procedural and substantive criteria that must be met to obtain such relief under CAA § 304.

12.4 The 100 kg/hr emissions threshold for defining a "super-emitter" is not adequately justified.

As a wholly different concern, EPA proposes to "define a super-emitter emissions event as any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater." *Id*. at 74749. While EPA provides a lengthy explanation of how that threshold was determined and why EPA believes it is appropriate, the overarching rationale is that the Agency believes that this threshold captures "very large emissions events." *Id*. Indeed, the term "super-emitter" clearly was coined to describe the intended scope of coverage.

Yet just a few months ago, when addressing essentially the same issue under Subpart W of the Greenhouse Gas Reporting Program, EPA proposed to establish a new reporting requirement for "other large release events," which EPA proposed to define as "events that release at least 250 mtCO_2e per event." 87 Fed. Reg. 36920, 36982 (June 21, 2022). In explaining its rationale for setting this threshold, EPA explains that, "[w]hile some sources covered by subpart W methodologies, such as equipment leaks, may represent ''malfunctioning'' equipment, these sources are ubiquitous across the oil and gas sector [and] are generally small." *Id*. The proposed 250 mt reporting threshold is intended to capture "large emissions events." *Id*. EPA derived the value by assessing "other emissions sources that [it] considered large." *Id*. The threshold was expressly designed to be considerably lower than the emissions rates estimated for the largest release events (e.g., Aliso Canyon or Ohio well blowouts), and compares favorably to a similar reporting requirement under Subpart Y for petroleum refinery flares. *Id*. at 36983.

Despite the obvious similarities between the proposed Subpart W large emissions event proposal and the proposed NSPS OOOOb and EG OOOOc super-emitter proposal, EPA fails to mention the Subpart W proposal when explaining in the NSPS OOOOb and EG OOOOc proposal its rationale for establishing the emissions threshold for super-emitting events. The omission is particularly striking given the significant differences between the two proposals as to what EPA believes to be a large-emitting event. For example, EPA proposes to apply a kg/hr metric in NSPS OOOOb and EG OOOOc versus an event-based metric for Subpart W. Additionally, the proposed NSPS OOOOb and EG OOOOc threshold of 100 kg/hr is facially much lower than the 250 mt per event threshold in Subpart W. The Subpart OOOOb and OOOOc proposal would define events as "super-emitting" that EPA in the Subpart W proposal dismisses as "ubiquitous" and "generally small."

Clearly, the two proposed rules are contradictory in many relevant aspects. EPA has not provided any explanation in the NSPS OOOOb and EG OOOOc original or Supplemental Proposals as to why the proposed definition of "super-emitter" makes sense in light of the proposed rules for large event release reporting under Subpart W.

Lack of such an explanation would render this aspect of the final NSPS OOOOb and EG OOOOc rule arbitrary and capricious. Moreover, even if EPA provides an explanation in the final rule, the definition of “super-emitter” is of central relevance to the Super-Emitter Response Program and, thus, failure to provide an opportunity for public notice and comment on its explanation would violate the CAA § 307(d) procedural rulemaking requirements.

12.5 EPA’s proposed approach to reconciling the applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc is contrary to law and unreasonable.

In our comments on the original proposal, we noted that the proposal did not include any discussion or analysis of the complex issues surrounding the applicability of the various NSPS OOOO subparts. We pointed in particular to the complexities related to the fact that the various subparts do not completely overlap – Subpart OOOO applies only to volatile organic compounds (VOCs), Subparts OOOOa and OOOOb apply to VOCs and greenhouse gases (GHGs), and EG OOOOc applies only to GHGs. Also, the affected/designated facilities are not the same under these rules. We also highlighted the question of whether a source that is an affected facility that is regulated as a new source under an existing NSPS can also be an “existing” facility under a subsequent CAA § 111(d) rule. Another important omission was any citation or explanation/analysis by EPA of the applicable law.

The Supplemental Proposal does not resolve these issues. To be sure, EPA provides an explanation of how it believes “the proposed EG OOOOc [will] impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa.” (87 FR 74716). But that explanation is fundamentally incomplete because EPA still does not provide any legal analysis explaining how or why its proposed analysis is required or allowed under the law. The full extent of EPA’s legal discussion on this topic is the conclusory assertion that:

> *Under CAA section 111, a source is either new, i.e., construction, reconstruction, or modification commenced after a proposed NSPS is published in the Federal Register (CAA section 111(a)(1)), or existing, i.e., any source other than a new source (CAA section 111(a)(6)). Accordingly, any source that is not subject to the proposed NSPS OOOOb as described is an existing source subject to EG OOOOc.*

Id. at 74716.

That simple explanation does not provide sufficient detail on the key legal questions we presented in our prior comments. For example, EPA does not explain how the law requires or can be interpreted to require a source to be regulated as a “new” source under a prior NSPS and, at the same time, be regulated as an “existing” source under a subsequent CAA § 111(d) program. It is clear that EPA presumes that this is how the law works. For example, the Agency repeatedly asserts that Subpart OOOOc standards “would satisfy compliance with” previously applicable NSPS – clearly implying that both standards would apply. See *Id.* at 74716-8. But the Supplemental Proposal does not explain why this outcome (applicability of both new and existing source standards to the same affected/designated facility) must or may be prescribed under the law.

EPA’s silence on this important matter is particularly pronounced because EPA has never taken the position a that previously applicable NSPS continues to apply to an affected facility that triggers the applicability of a subsequent standard. For example, VOC emissions from storage vessels are regulated under both Subpart OOOO and Subpart OOOOa. It is easily conceivable that a given storage vessel might have triggered Subpart OOOO because it was constructed one month after that standard was proposed and then subsequently triggered Subpart OOOOa because the storage vessel was modified two months after that standard was proposed. It is well understood that, in such a circumstance, the Subpart OOOO storage vessel requirements cease to apply after the corresponding

Subpart OOOOa requirements are triggered. The approach to reconciling applicability suggested in the Supplemental Proposal cannot be reconciled with EPA's historic practice.

More broadly, EPA fails in both the original and Supplemental Proposals to explain how the law must or can be construed to determine what standard applies to a given source when: (1) the source is regulated as a new source under a prior version of an NSPS (such as Subpart OOOO) and then triggers a subsequent version of that new source standard (such as Subpart OOOOa); (2) the source is regulated as a new source under an existing new source standard (such as Subpart OOOO or OOOOa) and is in existence when a subsequent Section 111(d) existing source standard is proposed (such as EG OOOOc) and subsequently take effect; and (3) a source is regulated as an existing source under a Section 111(d) standard (such as EG OOOOc) and is subsequently modified or reconstructed such that it triggers a corresponding new source standard (such as NSPS OOOOb).

In sum, EPA fails to acknowledge the complexities and ambiguities as to how the law applies to this situation and fails to provide relevant legal analysis on these points. Unless EPA corrects these problems, the final rule will be both procedurally flawed (for failure to satisfy the CAA § 307(d)(3) obligation for EPA to address in the proposed rule that major legal interpretations underlying the proposed rule and to provide an opportunity for public comment) and arbitrary and capricious (for failure to address key factors underlying applicability of the various subparts). We note the legal basis for the applicability scheme for these rules is an issue of central relevance because the scope of applicability is fundamental to proper implementation and coordination of these rules.

12.6 EPA must provide more flexibility for approving state programs.

The Supplemental Proposal includes a lengthy discussion of the approach and criteria by which EPA proposes to review and approve/disapprove state CAA § 111(d) existing source programs. We have comments and recommendations on several elements of EPA's proposed approach.

All of our comments flow from the fundamental guiding principle that EPA is required to approve state programs that satisfy CAA § 111(d) standard setting criteria and cannot approve state programs that do not meet those criteria.[100] EPA correctly sums up this principle when it states "that its authority is constrained to approving measures which comport with applicable statutory requirements" (87 FR 74826 n. 274). The problems with EPA's proposal regarding approval of state programs all are grounded in violations of this principle.

To begin, EPA exceeds its authority by seeking in many places to impose its own preferences on state programs rather than recognizing that it must approve any state program that meets the statutory criteria – even programs that include elements that EPA itself would not choose, but that objectively do meet statutory standard setting requirements. In other words, if a state program meets express statutory requirements or otherwise is grounded on a reasonable construction of statutory requirements, EPA has no choice but to approve the program.

For example, EPA repeatedly and wrongly asserts that its "presumptive standards" must be used to judge the adequacy of state programs. See, e.g., *Id*. at 74812 ("a state program must establish standards of performance that are in the same form as the presumptive standards"); *Id*. ("EPA is also proposing to interpret CAA section 111 to authorize states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards"). Using EPA's presumptive standards as a measure of acceptability is wrong because a state's obligation under CAA § 111(d) is to establish standards of performance based on BSER.

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[100] The only other state obligation is to satisfy the nominal procedural requirements that EPA establishes for submission, review, and approval of state CAA § 111(d) programs.

CAA §§ 111(a)(1) and (d)(1). EPA's "presumptive standards" do not constitute BSER. Rather, they represent EPA's notion of what emissions standard might reasonably satisfy EPA's BSER determinations. But the statute unambiguously provides that states have authority and responsibility to fashion a standard that meets BSER and is not limited to the "presumptive standard" that EPA thinks is best.

Notably, EPA clearly understands that is what the statute requires. EPA itself states that "Section 111(d) does not, by its terms, preclude states from having flexibility in determining which measures will best achieve compliance with the EPA's emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion" (87 FR 74812). EPA's acknowledgment that it is the states' obligation to determine what measures "best" satisfy EPA's BSER determination is a correct statement of the law and contradicts the idea that EPA gets to decide what is "best" and impose that judgment on the states.

On a related note, EPA here indicates its commitment to faithfully implementing the "framework of cooperative federalism that CAA section 111(d) establishes," which necessarily requires EPA to defer to (and approve) state measures that satisfy the law, even when such measures do not satisfy EPA's own preferences. See also *Id*. at 74826 (EPA proposing to defer to the state's discretion to impose more costly controls). Yet on the other hand, a primary rationale for the proposed prescriptive measures for reviewing and approving/denying state programs is concern about inconsistency from state to state (e.g., *id*. at 74818 ("two states could consider RULOF for two identically situated designated facilities and apply completely different standards of performance on the basis of the same factors")) and the possibility that certain state programs will be less stringent than EPA believes they should be (e.g., *id*. at 74817 (lack of a clear framework might allow states to "set less stringent standards that could effectively undermine the overall presumptive level of stringency envisioned by the EPA's BSER determination and render it meaningless")). EPA cannot have it both ways – i.e., support state flexibility when it promotes EPA's preferred outcomes and discourage state flexibility when needed to achieve such outcomes. Such an inconsistent approach is facially arbitrary. It is easily resolved by allowing the state flexibility that EPA acknowledges to exist and, in any event, that is demanded by the statute.

Another flaw in EPA's approach is its proposal to give substantive meaning to the statutory obligation that it must approve state plans that are "satisfactory." CAA § 111(d)(2)(A). For example, EPA explains that "it is the EPA's responsibility to determine whether a state plan is "satisfactory" (87 FR 74818). EPA further explains that "the most reasonable interpretation of a ''satisfactory plan'' is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d)." *Id*. See also *id*. at 74824 ("CAA section 111(d)(2)'s requirement that the EPA determine whether a state plan is ''satisfactory'' applies to such plan's consideration of RULOF in applying a standard of performance to a particular facility. Accordingly, the EPA must determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives.").

So, by EPA's reasoning, all elements of its CAA § 111(d) implementing regulations become mandatory state obligations because, if a state does not in EPA's eyes satisfy the regulations, the state program is not "satisfactory" to EPA. Similarly, EPA gets to decide whether a state plan is "satisfactory" based on EPA's judgment as to whether the plan meets EPA's conception of the "overall health and welfare objectives" of CAA § 111(d). In other words, EPA uses the term "satisfactory" to bootstrap its own policy and legal preferences into mandatory approvability criteria.

EPA's interpretation is inconsistent with the plain words of the statute and, in any event, unreasonably expands EPA's authority to prescribe or prohibit particular outcomes under state CAA § 111(d) programs. The statute

simply says that state plans must be “satisfactory.” The word “satisfactory” naturally connotes that EPA must approve any state plan that meets the statutory standard setting criteria and that otherwise meet the nominal procedural rules that EPA is required to establish to guide submission and review/approval of state plans. The word “satisfactory” does not reasonably confer upon EPA the authority to demand particular outcomes (e.g., meeting EPA’s self-determined “health and welfare objectives”) or to impose substantive constraints not otherwise specified by CAA § 111(d). EPA’s effort to give more meaning to the word “satisfactory” is inconsistent with the law and a misplaced effort to expand the Agency’s authority under CAA § 111(d).

Lastly, EPA explains that when a state decides to establish a standard of performance based on consideration of remaining useful life and other factors, it must “determine and include, as part of the plan submission, a source-specific BSER for the designated facility” (87 FR 74821). EPA then prescribes criteria that the state must follow in determining BSER and setting a corresponding emissions standard. *Id*. This is the first time in this rulemaking (and, to our knowledge, the first time ever) that EPA has interpreted the statute as authorizing and requiring a state to conduct a BSER analysis under CAA § 111(d) rather than setting standards of performance based on an EPA BSER determination.

We agree with EPA that, when a state considers RULOF in setting emissions standards for a particular source or group of sources, it necessarily must conduct a BSER analysis as part of its analysis. When a state considers RULOF, EPA’s own BSER analysis ceases to have meaning because fundamental elements of that analysis – such as the cost assessment and determination that a particular emissions control method is feasible or has been adequately demonstrated – cease to apply to the source(s) covered by the state RULOF analysis.

EPA asserts that “the statute requires the EPA to determine the BSER by considering control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating: (1) The cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology” and that “a state must also consider all these factors in applying RULOF for that source.” *Id*. We agree that the statute requires the first three criteria to be considered in determining BSER. We agree that application of these criteria is consistent with the principle that state CAA § 111(d) plans must meet the statutory standard setting criteria. We do not agree that the statute specifies or requires that BSER also must be based on an assessment of “the amount of reductions” or “advancement of technology.” A state has the discretion to consider these factors, but EPA cannot impose these factors on a state because the statute itself does not require that they be considered.

EPA goes on to assert that a state BSER analysis “must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG using the five criteria noted above.” *Id*. We disagree. The state clearly must determine BSER based on the express statutory criteria. But the law does not require a state BSER analysis to “identify all control technologies available for the source,” “use the same metrics,” or provide an evaluation “in the same manner” as EPA used in developing its BSER analysis. These may represent EPA’s preferred method of determining BSER, but nothing in the law requires a state to follow EPA’s preferred method or authorizes EPA to reject a state standard that is based on a BSER determination that employs a different approach than EPA’s.

12.7 EPA does not have authority to approve more stringent state programs that are based on consideration of remaining useful life and other factors.

In the original proposal, EPA offered an extensive explanation of why it now believes it has authority to approve state § 111(d) programs that are more stringent than would be required by application of the BSER determined by

EPA. That position is expanded in the Supplemental Proposal by EPA's assertion that "states may consider RULOF to include more stringent standards of performance in their state plans" (87 FR 74825). This position represents a complete reversal of the current Subpart B provision limiting application of "RULOF" to establishing less stringent measures (See 86 FR 63251).

EPA now asserts that the term "other factors" is ambiguous and that EPA "may reasonably interpret[] this phrase as authorizing states to consider other factors in exercising their discretion to apply a more stringent standard to a particular source" (87 FR 74825). Moreover, EPA now rejects the idea that the § 111(d) Subpart B variance provisions are relevant in interpreting the scope of the Agency's authority to approve more stringent standards based on consideration of RULOF. *Id*. EPA also rejects its prior analysis of the legislative history on the grounds that it provides no meaningful guidance to EPA. *Id*. at 74826. Lastly, EPA argues that its new interpretation is consistent with the purposes of CAA § 111(d) – i.e., "to require emission reductions from existing sources for certain pollutants that endanger public health or welfare." *Id*.

EPA's attempt to reverse its position here is misplaced and is not supported by the law. First, as we discuss above, the term "other factors" is not a carte blanche invitation from Congress for EPA to create whatever plausibly "reasonable" new authorities or constraints it might conceive. The term "other factors" must be interpreted in context. As EPA itself explains, the term "remaining useful life … is a factor that inherently suggests a less stringent standard." *Id*. In this context, it stands to reason that Congress intended the term "other factors" to be interpreted such that "other factors" are applied in the same way (to reduce rather than increase stringency). Because the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term "other factors" must be construed in this manner.

Second, EPA's position is grounded in its assertion that states are not required "to conduct a source-specific BSER analysis for purposes of applying a more stringent standard" because "[s]o long as the standard will achieve equivalent or better emission reductions than required by EG OOOOc, the EPA believes it is appropriate to defer to the state's discretion to, e.g., choose to impose more costly controls on an individual source." *Id*. at n. 273. At the same time, EPA correctly notes that "its authority is constrained to approving measures which comport with applicable statutory requirements." *Id*. at n. 274; see also *Id*. at 74813 (EPA may not approve and thereby "federalize" state programs that apply to pollutants and/or affected facilities not covered by Subpart OOOOc).

It is inconsistent and arbitrary for EPA to assert that a state must conduct a new source-specific BSER analysis if it wants to use RULOF to establish a less stringent standard than would be required under EPA's BSER determination (see *Id.* at 74821), while a state is not similarly constrained when establishing more stringent standards. EPA's assertion that a more stringent standard does not require a BSER analysis because it "will achieve equivalent or better emissions reductions than required by EG OOOOc" cannot be squared with the requirement that alternative state measures must "comport with applicable statutory requirements" – which in this case include the unambiguous requirement that BSER and corresponding emissions standards must be demonstrated in practice and cost effective. EPA's suggestion that it may defer to (and approve) more stringent state requirements simply because they are more stringent is wrong because that approach does not ensure that the more stringent standards meet the statutory standard-setting criteria.

12.8 The proposed well closure requirements are not needed as a practical matter and mostly beyond EPA's authority as a legal matter.

In the original proposal, EPA raised in concept the possibility of setting standards "to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged

ineffectively" (86 FR 63240). We explained in our comments that emissions from abandoned wells are not as great as EPA suggests and that issues related to well closure are more appropriately addressed by the states and BLM. We also explained that, if EPA decided to move ahead with such standards, the possibility of requiring a demonstration of financial capacity should not be a part of that proposed rule given EPA has no authority under the Clean Air Act to impose a financial assurance requirement.

In the Supplemental Proposal, EPA proposes regulations governing well closures in both NSPS OOOOb and EG OOOOc (87 FR 74736). The proposed rules closely track the concept outlined in the original proposal – including a requirement for developing and submitting a well closure plan within 30 days of the cessation of production from all wells at a well site, which must describe the steps that will be taken to close the well, proof of financial assurance, and a schedule for completing the closure. *Id*. Monitoring must be conducted after closure to demonstrate that there are no emissions from the closed well. *Id*. And changes in ownership must be reported on an annual basis during the life of a well. *Id*.

In light of this proposal, we reiterate our prior argument that the CAA does not grant EPA authority to impose financial assurance requirements.[101] We add that EPA did not respond to these comments in the Supplemental Proposal. We further note that EPA did not explain the legal basis for the proposed financial assurance requirements in either the original or Supplemental Proposal. Indeed, EPA cites no legal authority and provides no legal analysis for any aspect of the proposed well closure standards. Such an explanation is needed for such a key and novel aspect of this proposed rule so that interested parties have the opportunity to formulate and submit comments on EPA's legal rationale. CAA § 307(d)(3). The final rule will be procedurally deficient if EPA does not cure this problem.

Lastly, EPA provides little new evidence or arguments in the Supplemental Proposal as to why well closure standards are warranted. EPA appears to rely on the more extensive discussion provided in the original proposal. Notably, that discussion focuses on "abandoned wells" (i.e., "oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells") "that are not plugged or are plugged ineffectively." (86 FR 63240). The discussion particularly targets "orphan wells" – i.e., those that have been abandoned and for which "there is no responsible owner." *Id*. EPA explains that the proposed well closure standards constitute a "potential strateg[y] to reduce emissions from these sources." *Id*. at 63241.

EPA explains in passing that states and other federal government agencies regulate well closures and have programs to address abandoned and orphan wells. Yet EPA does not conduct an in-depth assessment of these programs or make any attempt to distinguish how much of the perceived problem with abandoned or orphan wells relates to wells that pre-date the current federal and state programs versus wells that are regulated by such programs. In other words, EPA asserts that well closure standards are needed to address the problem of emissions from abandoned or orphan wells but does not determine that current state and federal programs are somehow deficient and, therefore, need to be supplemented by EPA standards going forward.

If EPA had delved more deeply into the current state of affairs, it would have seen that industry, states, and other federal government agencies are making great progress in addressing abandoned and orphaned wells. For example, the federal Bureau of Land Management highlights on its website its extensive regulatory and non-regulatory efforts to address orphan wells, including the hundreds of millions of dollars allocated by Congress in

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[101] Comment 10.1.1 on page 40 in EPA-HQ-OAR-2021-0317-0808

the recent "Bipartisan Infrastructure Law" to support tribal, state, and federal efforts in this area. EPA does not even mention the Bipartisan Infrastructure Law in the original or Supplemental Proposals.

Before finalizing the proposed well closure standards, EPA needs to consider more closely the current regulatory landscape, the extensive non-regulatory measures focused on abandoned and orphaned wells, and the expansive voluntary efforts by industry to address this important issue. Those factors are critical to understanding whether EPA rules are needed and, if so, how they should be designed and implemented.

12.9 The Supplemental Proposal would impose unreasonable, impractical, and unduly burdensome certification requirements.

The applicability of several elements of the proposed rule depends on a certification of technical infeasibility that must be executed by a professional engineer or other qualified individual. Examples include the use of an emissions control device to handle associated gas (see, e.g., proposed § 60.5377b(b)(2)), the continued use of pneumatic pumps driven by natural gas (see, e.g., § 60.5393b(c)), and the use of emitting gas well unloading methods (see, e.g., §60.5376b(c)(2)(ii)(B)(2)). EPA imposes these certification requirements out of concern about the possible "abuse" of these provisions such that they might open a "loophole" in the regulations (87 FR 74776). EPA stresses that it, "wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties." *Id*. Thus, the proposal raises the serious prospect of individual, personal liability, not only for fraudulent certification, but also for technically erroneous (i.e., "significantly flawed") certifications.

As we discussed in our comments on the original proposal, we support these opt out provisions as a practical matter. We agree that non-emitting measures and methods should be used where they are technically feasible and cost effective. But EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. The proposed alternative measures are a common-sense solution.

But our comments on the original proposal also expressed the concern that EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating opt outs. We pointed out that the need to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA §111 because non-emitting standards are not "adequately demonstrated" if opt outs are needed to make them feasible and workable.

We reiterate those concerns about the legal basis for EPA's opt-out approach because onerous and potentially punitive certification requirements make the opt out approach even more legally tenuous. To begin, such certification requirements will significantly limit the situations where an opt out can be employed. As a result, what otherwise might be a reasonably viable alternative to an unworkable zero-emissions standard is unnecessarily complicated by strict certification requirements tied to an undefined standard that will be difficult to apply and limit the usefulness of the alternative. That heightens the concern that creating an opt out is unlawful circumvention of the obligation to demonstrate that BSER and the corresponding standards of performance are adequately demonstrated and cost effective.

Moreover, the proposed certification requirements are unreasonably onerous because, in each case, the certifying individual must essentially prove a negative – that the otherwise applicable zero-emissions approaches

are "technically infeasible." There is no definition of technical infeasibility in the proposed rules, but the words could be construed as setting an exceedingly high bar, such that a given non-emitting technique is "infeasible" based solely on a technical assessment of whether it can theoretically be physically applied in the given situation. So, for example, that might require a non-emitting technology to be applied because it is technically theoretically possible, even though it would be inordinately expensive. This outcome would not be lawful because it would violate the statutory requirement that BSER and the corresponding standard of performance must be cost effective.

And, in any event, a "technical infeasibility" standard allows for second guessing by regulators or citizen enforcers, which invites a "battle of the experts" in potential enforcement actions. All of this diminishes the possibility that the opts outs can be implemented with reasonable certainty.

Lastly, the express threat of possible personal liability on the part of certifiers surely will limit the number of individuals willing to make the needed certifications, particularly in light of the uncertainties described above about what will be needed as a practical matter to demonstrate "technical infeasibility." The clear opportunity and possibility of second guessing will be further material disincentives.

We provide here three recommended solutions to these problems. First, rather than creating opt outs that require case-specific certification, EPA should establish the opt outs in the final regulation as regulatory alternatives that may be employed if specified criteria in the rule are met. This is the usual method of prescribing standards of performance and regulatory compliance alternatives, and it would not be difficult for EPA to structure the rule in this fashion.

Second, as explained above, one of the legal flaws in EPA's opt-out scheme is that technical feasibility is the only governing criterion. The cost of implementing the default zero-emitting standard is not a consideration. As a result, the proposed opt-out approach unlawfully evades the obligation that cost must be considered in prescribing CAA § 111 standards of performance. This flaw is easily cured by including cost as a consideration in implementing the opt-out provisions.

Third, if EPA retains the requirement for case-specific certifications, EPA should revise the required certification. The proposed regulatory text of each certification includes the following sentence: "Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete." See, e.g., § 60.5377b(b)(2). This should be revised to specify that the certification is based on "reasonably inquiry," as is required for certifications under the Title V operating permit program. The revised certification could read as follows: "Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, …." A "reasonable inquiry" standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

12.10 EPA should not define and impose practical enforceability requirements without first developing a consistent approach for all EPA programs.

In the original proposal, EPA proposed "to include a definition for a 'legally and practicably enforceable limit' as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules" (86 FR 63201). EPA explained that "[t]he intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected

facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy." *Id*.

In our comments on that proposal, we urged EPA to defer final action on the proposed definition until such time as the Agency undertakes a broad-based rule that would provide a single, consistent approach across all affected CAA programs. Such an approach would prevent potential inconsistencies among the various CAA programs (e.g., an effective emissions limit used to avoid major New Source Review (NSR) permitting might, at the same time, not be effective for purposes of the OOOOb and/or EG OOOOc storage vessel standards); would avoid the possible implication that the "effectiveness" criteria established under EG OOOOc should be applied under other CAA programs (i.e., how can an emission limit be both effective and not effective at the same time), and allow EPA to establish reasonable transition rules so that affected sources and states have time to revise existing emissions limitations as needed to meet the new effectiveness criteria.

In addition, few existing sources have express emissions limitations for methane or GHGs. Yet, EPA has newly proposed a 20 tpy methane applicability trigger for the Subpart OOOOb and OOOOc storage vessel standards (in addition to the 6 tpy VOC trigger) (87 FR 74800). As a result, many potentially affected/designated facilities likely will seek to rely on VOC emissions limitations as a surrogate for methane emissions. The use of surrogates in establishing effective potential to emit (PTE) limits is another cross-cutting issue for which EPA should establish a unitary CAA approach rather than the proposed piecemeal, rule-by-rule approach.

We raise these issues again because EPA recently announced its intention to issue national guidance on establishing effective limits on potential to emit.[102] That effort appears to be driven by a July 2021 report from the EPA Inspector General that criticized the Office of Air and Radiation for not responding to a series of 1990's era D.C. Circuit decision that vacated or remanded the then "federal enforceability" criteria that applied across EPA's CAA regulatory programs.[103] EPA intends to issue national guidance by October 2023.

EPA's announced plan to establish national rules for effective limits on PTE and to do so in the relative near future lends strong additional support to our request that EPA should not address these issues in a premature and piecemeal fashion in the EG OOOOc rule.

13.0 Other General Comments

13.1 Due to the unreasonably short duration of the comment period for the Supplemental Proposal, API has been unable to respond to all of EPA's comment solicitations.

The proposed NSPS OOOOb and EG OOOOc are both complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, many stakeholders requested an extension of the comment period in order to provide the agency with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. Concurrent with this rulemaking there are additional and overlapping regulatory developments on this subject matter including the Inflation Reduction Act Methane Emissions Reduction Program, EPA's Redesignation of Portions of the Permian Basin for the 2015 Ozone

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[102] *NAAQS, Regional Haze & Permit Program Implementation Updates*, Presentation by Scott Mathias, Director Air Quality Policy Division, OAQPS, to AAPCA Fall Meeting (Sept. 29, 2022).

[103] *EPA Should Conduct More Oversight of Synthetic-Minor-Source Permitting to Assure Permits Adhere to EPA Guidance, Report No. 21-P-0175*, memorandum from Sean W. O'Donnell to Joseph Goffman (July 8, 2021) at 17.

National Ambient Air Quality Standards, EPA's Proposed Updates to the National Ambient Air Quality Standards for PM and the Bureau of Land Management's proposed Waste Prevention Rule that all must be reviewed in accordance with the overlapping aspects of these various actions.

To provide a complete set of comments on a rulemaking as broad, impactful, precedent setting, and complex as proposed within NSPS OOOOb and EG OOOOc, API requested an additional 60 days to gather information and submit comments. Not only did EPA decline API's and other stakeholders' reasonable request for a 60-day extension of the comment period, EPA did not grant even an additional two weeks as the Agency did for the initial proposal[104], which was smaller than the Supplemental Proposal. As we have stated in Comment 12.1*,* we recognize that every administration has the right to set and implement its regulatory agenda. Nevertheless, that this Administration would expedite issuance of the original proposed rule to align with COP26[105], delay issuance of the Supplemental Proposal to align with COP27[106], and then deny the request of pertinent stakeholders to have adequate time to provide fully-informed feedback to EPA, undermines this Administration's stated goals of reducing emissions in the service of political optics. API has developed as complete a set of comments provided herein as time has allowed. However, much of the information EPA requested, as well as additional information API wanted to provide, is not included herein due to the arbitrary and unnecessarily imposed timing constraints of the comment period for the Supplemental Proposal. We restate our industry's shared goal with EPA of reducing emissions from oil and natural gas operations across the value chain. We remain concerned that this Administration will rush to the completion of a final rule that is not cost-effective, technically feasible, or legally sound. We strongly encourage EPA to adopt the recommendations in our comments to enable the final rule to meet these critically important criteria.

13.2 EPA should reduce burden associated with the collective recordkeeping and reporting requirements.

Proposed NSPS OOOOb and EG OOOOc include onerous recordkeeping and reporting that exceed typical levels of compliance assurance and are a significant cost to operators to track and maintain. EPA should continue to focus on having operators track the most necessary information to obtain assurance.

In this proposal,

- EPA increased the recordkeeping and reporting requirements without adequately justifying increased costs with respect to the administrative burden these proposed changes would require, including numerous technical demonstrations and engineering statements. Increased costs associated with administrative burden are disproportional to benefit – because benefit is marginal when compared to other mechanisms that are already in place and proposed elsewhere in this rulemaking that focus on necessary information to assist in ensuring compliance.
- EPA continues to ignore the scale of affected/designated facilities that will become subject to these provisions over time, which is well over the tens of thousands.
- EPA has included reporting requirements that are outside the Agency's jurisdiction in requiring details on well ownership transfers.

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[104] https://www.federalregister.gov/documents/2021/12/17/2021-27312/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for

[105] https://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health

[106] https://www.epa.gov/newsreleases/biden-harris-administration-strengthens-proposal-cut-methane-pollution-protect

API recognizes that it is appropriate to maintain sufficient records to demonstrate compliance. However, it is API's view that it is excessive to require such a significant level of detail to be both documented and submitted for all of the affected/designated facilities in this proposal. EPA should simplify the recordkeeping and reporting requirements to those that assure compliance without additional administrative burden. Only elements needed for compliance assurance should be requested within the annual report as supporting records retained by companies can be made available upon request from the Agency.

API has provided some initial comments on certain recordkeeping and reporting aspects of proposed NSPS OOOOb and EG OOOOc throughout this comment letter, but due to the short comment period have not had adequate time to fully assess the impact of what EPA has proposed. Some initial thoughts on the proposed draft reporting form template include the following:

- One initial concern is that many companies do not allow the use of workbooks containing macros as a cybersecurity measure and the current draft workbook contains macros. If the form is dependent on the macro formatting, this may be an issue for some reporters using the form.
- We do not support the reporting of additional information related to well transfers (including name, phone number, email, and mailing address) as proposed §60.5420b(b)(1)(v).
- The control device and closed vent system tabs are set up where multiple affected facilities that route to a single control device or through the same closed vent system cannot be identified on a single row. This will result in redundant and duplicate information being reported.
- Certain selection options for "Deviation Category" the "Description of Deviation" and "Type of Deviation" cells are automatically blacked out and do not allow an operator to provide additional context. The operator should have the ability to add free text in these areas and provide additional information as needed.

We will continue to review the recordkeeping and reporting requirements proposed within these rules along with the draft reporting form (EPA-HQ-OAR-2021-0317-1536_content) and continue to provide EPA feedback on ways to streamline the template.

13.2.1 CEDRI System Concerns

Our members have concerns with the practical implications with reporting through CEDRI when/if there is a system outage. Specifically, we request EPA evaluate the following language as proposed under NSPS OOOOb and EG OOOOc, but note these concerns also apply to NSPS OOOOa:

- §60.5420b(e)(2): We believe this paragraph should be removed or, at a minimum, be inclusive of the compliance end period and the compliance submittal date. Staff scheduling submittal may choose to do so prior to 5 days before the compliance submittal date. If EPA is requiring the use of the reporting form within CEDRI, then it should not be in deviation on the operator in any circumstance.

- §60.5420b(e)(4): The requirement for the reporter to notify EPA immediately upon discovery of an outage is unduly burdensome for the reporter. EPA should manage the reporting system and notify registered users of an outage.

- §60.5420b(e)(5)(iii): It is unclear what EPA is intending for a reporter to include as far as "a description of measure taken to minimize the delay in reporting". EPA should be taking action to minimize the delay in reporting if there is a CEDRI system outage. The regulated entity has no additional recourse in this instance.

- §60.5420b(e)(6): System outage should warrant automatic claims to those submitting reports. Operators should not be penalized when the only method for submittal is not available and out of their control.

- EPA should implement a secure process, similar to EPA's e-GGRT program, to prevent those who are not owners or operators or are authorized representatives of an affected facility from submitting to CEDRI for any affected facility.

13.3 EPA should clarify its statements regarding the Crude Oil and Natural Gas source category and the extent of crude oil operations for purposes of this rulemaking.

Within proposed NSPS OOOOb and EG OOOOc the Crude Oil and Natural Gas source category is defined consistent with historical definitions finalized in NSPS OOOO and NSPS OOOOa:

> *Crude oil and natural gas source category means:*
>
> > *(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and*
> > *(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.*

In footnote 301 (87 FR 74833), EPA states:

> [301] "*For purposes of the November 2021 proposal and this supplemental proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.*

We do not believe that EPA intends to regulate crude oil operations beyond the point of custody transfer from a well to a transmission pipeline and we request that EPA clarify and correct these statements in the final rule to align with the definition of the source category as proposed.

13.4 Applicability for Inactive sites and Reactivation of Inactive Sites

Many sites may periodically shut-in or depressurize all or partial equipment, where the entire site might be inactive or certain equipment might be inactive. We believe this is an appropriate criterion for exemption for all affected or designated facilities under NSPS OOOOb and EG OOOOc. At a minimum, we seek clarification as the status of inactive facilities and depressurized equipment as they pertain specifically to fugitive emission monitoring (Comment 2.5) and the retrofit of pneumatic controller and pneumatic pump provisions under EG OOOOc. We do not believe it is EPA's intent to require facilities that are not in active operations to retrofit the pneumatic controllers at the facility to non-emitting nor would it be appropriate for equipment that has been depressurized and inactive to be screened for fugitive emission monitoring.

Additionally, some inactive sites or equipment might be put back into service, where the applicability under NSPS OOOOb versus EG OOOOc must be delineated. One example is under *Pennsylvania's § 127.11a. Reactivation of sources*, which allows: *"a source which has been out of operation or production for at least 1 year but less than or equal to 5 years may be reactivated and will not be considered a new source if the following conditions are satisfied…".* EPA already has included language addressing this concept as it pertains to storage vessels. We

believe EPA should extend this concept to all affected and designated facilities. If a site that was inactive were to become active, there should be adequate time for the site to comply with the provisions within EG OOOOc.

13.5 The Social Cost of Greenhouse Gases

API shares the Administration's goal of reducing economy wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the EPA's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

In Attachment B, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine provided to the IWG.

13.6 Cross Reference and other Minor Clarifications

Below are some cross reference and other typos we have identified within the prosed NSPS OOOOb and EG OOOOc regulatory text.

- Subpart OOOOc makes eight references to a §60.5933c, one of which gives its title as "Alternative Means of Emissions Limitation." However, there is no actual section in EG OOOOc with that number or title.
- §60.5413b(d)(11)(iii): *A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC and methane (if applicable) required under this subpart.*
- §60.5370b(a)(1)(iii) refers to §60.5385b(a)(3), which does not appear to exist.
- The additional citations should be checked for correct cross referencing: §60.5420b(c)(2)(ii)(B), §60.5410b(f)(2)(iv)(B), §60.5420b(b)(10)(vi), and §60.5420b(c)(12).

Attachment A

Responses to EPA Solicited Comments for Use of Optical Gas Imaging in Leak Detection

Responses to EPA Solicited Comments for Use of Optical Gas Imaging (OGI) in Leak Detection

VI.C OGI Monitoring Requirements – Specifying Dwell Time to Account for Scene Complexity

[T]he EPA is soliciting comment on how dwell time could be based on the scene while still accounting for the differences in the complexity of scenes or ways to create bins for “simple” and “complex” scenes.

Response: *The most intuitive method to differentiate between “simple” and “complex” scenes would be to base it on the number of components being imaged and viewing distance. An example of a “simple” scene would be a scene of 20-25 components viewed at a distance of < 15-25 feet. This approach offers a high probability of leak detection by a technician. The high probability of detection is supported by existing operating envelope testing conducted by camera manufacturers which demonstrated consistent image detection at these distances at delta-T as low as 2 degrees C. Moreover, the number of components being limited to 25 in a simple scene means a technician is likely to have great discernment or granularity of the image which improves their ability to detect image of a leak. “Complex” scenes would be when there are greater than 25 components or viewing distances greater than 25 feet.*

VI.C OGI Monitoring Requirements – Ensuring OGI Camera Operators Survey a Scene is Adequate Without Specifying Dwell Time

The EPA is also soliciting comment on ways to similarly achieve the goal of ensuring that OGI camera operators survey a scene for an adequate amount of time to ensure there are no leaks from any components in the field of view without specifying a dwell time.

Response: *The “simple” scene criteria offered previously ensures that a technician has optimum image detection consistent with operating envelopes of camera. Specifying a dwell time for these types of scenes would be irrelevant as the technician will be looking closely at the scene in their viewfinder looking to detect any imagery. Placing a constraint of dwell time would complicate their efforts and distract from their efforts at viewing the scene. A well-trained technician who consistently passes their performance audits will be expected to make a diligent and careful survey of the components in the scene.*

VI.C OGI Camera Operators – Performance Audit Frequency

The EPA believes that it is important to verify the performance of all OGI camera operators, even the most experienced operators, on an ongoing basis. Nevertheless, the EPA is requesting comment on whether there should be a reduced performance audit frequency for certain OGI camera operators, and if so, who should qualify for a reduced frequency, what the reduced frequency should be, and the basis for the reduced frequency.

Response: *The performance audit requirements can become a significant time-consuming activity for site(s) with large numbers of technicians in their survey crew. In the initial stages of OGI monitoring implementation, more frequent performance audits have a key role to play in ensuring technician efficacy. However, technician monitoring proficiency will increase quickly over time as their monitoring experience and time doing surveys increases. The*

agency's reference to the MTEC study clearly documented this to be the case. As such, for technicians who consistently have satisfactory performance audits, it is appropriate to extend the interval between audits for those technicians. A simple methodology to do so is to follow a "skip period" approach to performance audits. For technicians who pass four consecutive quarterly performance audits, then their audit interval should be extended to semi-annual. For technicians who pass two consecutive semi-annual performance audits, then their audit interval should be extended to annual. If a technician does not pass a semi-annual or annual audit or conduct a monitoring survey during the previous 12 months per Section 10.5 of Appendix K, then quarterly performance audits would be restarted.

VI.C OGI Surveys – Length of Survey Period

[T]he EPA has heard anecdotally that this may have more to do with the number of hours the OGI camera operator has surveyed during the day, such that it is more appropriate to limit the hours of surveying per day than it is to mandate rest breaks at a set frequency. The EPA is seeking any empirical data on the topic of the necessity of rest breaks when conducting OGI surveys or the link between operator performance and length of survey period.

***Response**: Fatigue potential is directly related to duration of continuous viewing through the camera and holding the camera in viewing position for extended periods. OSHA already has appropriate guidelines for ergonomics in the work place which include eye strain etc. Sites already have rigorous guidelines and safeguards for ergonomics, heat stress, etc. EPA should not attempt to develop regulatory standards for technician rest breaks. The agency should simply state that the monitoring plan incorporate appropriate rest breaks for technicians and simply state a rest break is required if the technician has been conducting a continuous viewing through OGI camera for 20 minutes or more. It is important to note that technicians would rarely have a 20-minute continuous viewing scenario. The primary monitoring method is to survey a component or scene for 1-2 minutes and then move to next location. When moving viewing locations, the technician would lower the camera to a neutral position and not be "viewing" though camera.*

VI.C Adequate Delta-T – OGI Camera

The EPA is proposing that the monitoring plan must describe how the operator will ensure an adequate delta-T is present to view potential gaseous emissions, e.g., using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view. […] [A] commenter stated guidance should be added for operators who are using a background temperature reading in the OGI camera field of view. The EPA is requesting comment on ways that an OGI camera operator can ensure an adequate delta-T exists during monitoring surveys for cameras that do not have a built-in delta-T check function.

***Response:** The simplest and most straightforward way for a technician to ensure adequate delta-T is to utilize the camera's function to display the temperature of the equipment or background behind the component being surveyed for leaks. Most, if not all, OGI cameras in use for leak surveys have this ability currently. As such, if the technician knows the ambient temperature, then it is a simple step to add/subtract the background from ambient to determine delta-T. The elegance of this approach is it allows the technician to adjust their angles or take additional steps in*

real-time during the survey process to ensure the delta-T of the operating envelope is maintained during any survey step.

VI.C Daily OGI Camera Demonstration Prior to Imaging to Determine Maximum Distance for Imaging

[O]ne commenter suggested that instead of having different operating envelopes for different situations and having to decide which envelope to use, the OGI camera operator should conduct a daily camera demonstration each day prior to imaging to determine the maximum distance at which the OGI camera operator should image for that day. The EPA believes that this type of determination would be more difficult and costly than creating an operating envelope, as it would require OGI camera operators to have necessary gas supplies on hand and take time to do this determination daily, or potentially multiple times a day. Nevertheless, the EPA is requesting comment on this suggestion, as well as how such a demonstration could be used if conditions on the site change throughout the day, at what point would the changed conditions necessitate repeating the demonstration, and how changes in the background in different areas of the site (such as to affect the delta-T) would be factored into such a demonstration.

Response: *Use of pre-defined operating envelopes through testing as prescribed in Section 8.0 of Appendix K is a highly useful and pragmatic methodology to determine detection capability and restrictions for monitoring surveys. It is expected that most OGI camera manufacturers plan to have completed the development of the operating envelopes after Appendix K is promulgated. However, the option for a site to do a daily or site-specific distance check utilizing a known gas concentration and flow rate at actual metrological conditions prior to conducting monitoring surveys should remain an option for a site.*

The reasons for retaining an option for a daily distance check are two-fold. First, a site may be conducting monitoring surveys with an OGI camera that does not yet have established operating envelopes. This could occur for a site using an OGI camera new to market or simply that initial monitoring surveys are planned to improve emissions reductions potential prior to the manufacturer publishing operating envelopes. Second, a site may believe that monitoring conditions for a given survey or site are unique with respect to pre-defined operating envelopes and want to ensure that the guidance on delta T and distance are appropriately set for the technicians' survey task. It is logical to include this option in Appendix K.

With respect to changing conditions, technicians should already be trained in recognition of factors (e.g., meteorological conditions) which would impact the leak detection capability. When conditions are significantly different then the technicians should switch to another operating envelope or conduct another distance check verification. This is already adequately addressed in Section 9.2.3. language.

Comments for Appendix K

"Appendix K. The EPA is not including a requirement to conduct OGI monitoring according to the proposed appendix K for well sites or centralized production facilities, as was proposed in the November 2021 proposal. Instead, the EPA is proposing to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21." [FR74723]

Comment: *This is the correct decision and recognizes the fundamental differences between upstream production and other industry sectors.*

Definition of fugitive emissions component. The EPA is proposing specific revisions to the definition of fugitive emissions component that was included in the November 2021 proposal. First, the EPA is proposing to add yard piping as one of the specifically enumerated components in the definition of a fugitive emissions component. While not common, pipes can experience cracks or holes, which can lead to fugitive emissions. The EPA is proposing to include yard piping in the definition of fugitive emissions component to ensure that when fugitive emissions are found from the pipe itself the necessary repairs are completed accordingly. [FR 74723]

Comment*: Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.*

Definition of fugitive emissions component. Based on changes made and discussed under section IV.A.1.a.ii of this preamble, the EPA is proposing to define fugitive emissions component as any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and CVS not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping. [FR 74736]

Comment*: The agency has consistently set VOC and VHAP content criteria in all previous fugitive emissions component monitoring requirements. These thresholds were typically defined as "in VOC service" which specified 10% VOC as the appropriate level where the emission reduction potential from leaking components was cost-beneficial. The agency stated that no data had been offered to support a one percent methane threshold and that produced water and wastewater streams can be significant sources of emissions. In the cited reference document ''Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations.'' Final Report. California Air Resources Board. May 2020, it stated that concentrations of compounds in the liquid phase were the best prediction of expected air emissions. This is correct and makes the point of industry comment to set a definitive threshold where cost beneficial emissions can be expected. Emissions potential is directly related to the concentration of methane and/or hydrocarbon in the process stream. Small concentrations of VOC (<10 wt%) and methane do not represent significant emissions potential; a fact that the agency has recognized in multiple updates to fugitive emission regulations.*

The apparent agency approach was simply to set the threshold at a single molecule which is inconsistent with decades of regulatory approaches to fugitive emission control methodology. As the relative proportion of VOC or methane in the given component goes down, the cost effectiveness of LDAR gets increasingly less favorable until, when the amount of VOC or methane approaches zero, the cost effectiveness value approaches infinity. The agency must consider cost for BSER determination. The content threshold used within the agency's cost effectiveness analysis is unclear. Either the agency used the traditional threshold content approach for estimating the potential regulated component inventory or it has overstated the cost effectiveness through the overstatement of emissions potential from components with very small methane and VOC contents.

In the preamble, the agency stated that industry had offered no empirical data to not establish an appropriate threshold. The agency has not demonstrated why a 1% methane and 10% VOC threshold are not appropriate, or how meaningful and cost-effective emission reductions are achieved at levels below those proposed by industry. This demonstration was not met by the agency in their definition of "potential to emit" and therefore the agency has not justified their decision. The recommendation to set the definition to include the VOC threshold at 10% and methane at 1% is an appropriate good faith effort by industry to reduce emissions.

EPA proposed that where a CVS is used to route emissions from an affected facility, the owner or operator would demonstrate there are no detectable emissions (NDE) from the covers and CVS through OGI or EPA Method 21 monitoring conducted during the fugitive emissions survey. Where emissions are detected, the emissions would be considered a violation of the NDE standard and thus a deviation. [FR 74804]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. These standards mandate that closed-vent systems are monitored annually with 5/15-day repair criteria. Routine AVO monitoring rounds by unit operators is also a standard work practice. CVS piping and components have been consistently found to have low leak percentages which makes sense when one considers that most of these components remained in a fixed configuration (i.e.., car-sealed open) and there is little to no operating changes of the FECs.*

The agency proposed action to make any emissions detection a violation is also a departure from historical leak detection and repair regulatory standards. EPA stated that their logic was that the NDE requirement was an emission standard and as such it has to be a violation even if repair provisions were allowed. This is an inappropriate regulatory approach since the NDE requirement should be considered a work practice standard rather than a numerical emissions standard. The CVS and control device requirements are sufficient to ensure that NDE operating conditions are the norm. The fact that the agency has prescribed monitoring survey requirements indicates the agency knows this paradigm to be true. The most important aspect of leak detection is routine surveillance of components and piping at appropriate intervals with prompt repair to stop the leak. The current 5-15 day repair timelines achieves this fundamental precept of LDAR, and making any leak detection a violation is an unnecessary addition to the requirements that does not expedite repairs or provide environmental benefits. Violations occur when repairs are not completed per requirements and/or routine monitoring is not conducted on-time or efficaciously.

In addition to this bimonthly OGI monitoring requirement, the EPA is also proposing to require OGI monitoring of each pressure relief device after each pressure release, as it is important to ensure the pressure relief device has reseated and is not allowing emissions to vent to the atmosphere. The EPA is soliciting comment on this change from a no detectable emissions standard to a bimonthly monitoring requirement. Where the EPA Method 21 option is used, we are proposing quarterly monitoring of the pressure relief device in addition of monitoring after each pressure relief. A leak is defined as an instrument reading of 500 ppm or greater when using EPA Method 21. [FR 74807]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. The most recent and stringent precedent for PRDs is found in the Part 63 Subpart CC which*

requires monitoring post-release to verify re-seating of PRD. The agency has consistently followed this approach in other RTR evaluations which makes this approach inconsistent with agency's technical analysis.

Not requiring routine monitoring of PRDs makes sense if one considers that if PRDs are properly seated then they are assumed to be in non-venting condition. Monitoring post-release is sufficient to ensure the emission standard is maintained.

EPA is proposing a requirement to monitor the CVS at the same frequency (i.e., bimonthly OGI in accordance with appendix K or quarterly EPA Method 21) as other equipment in the process unit and to repair any leaks identified during the routine monitoring. [FR 74808]

Comment: *In existing and recently revised NSPS and NESHAP standards for closed vent systems and control devices, the agency has prescribed initial inspection and on-going annual AVO inspections. The agency indicated there would be no cost to do these surveys, but that is incorrect. The monitoring survey routes would have to be expanded to include the CVS piping/ductwork sections which increases labor costs based on increased technician field survey time.*

Appendix K

EPA is proposing to revise the scope and applicability for appendix K to remove the sector applicability and to base the applicability on being able to image most of the compounds in the gaseous emissions from the process equipment. The EPA is retaining the requirement that appendix K does not on its own apply to anyone but must be referenced by a subpart before it would apply. [FR 74837] (App K VI.B.1)

1.3 Applicability. This protocol is applicable to facilities when specified in a referencing subpart. This protocol is intended to help determine the presence and location of leaks and is not currently applicable for use in direct emission rate measurements from sources

Comment: *This change in applicability is the correct approach. However, consistent with previously submitted comments on the proposed rulemaking, we recommend EPA proceed expeditiously to amend part 63 subpart CC (RMACT 1) to allow use of OGI technology and Appendix K as an alternative to Method 21 for refineries. In the recent Refinery Sector Rulemaking, EPA proposed allowing for use of OGI as an alternative to Method 21, but did not finalize that proposal because "we have not yet proposed appendix K."[107] Adding OGI as an alternative to RMACT 1 would significantly reduce the refinery and Agency resources associated with preparing and reviewing Alternative Method of Emission Limitation or Alternative Monitoring requests to allow OGI for those facilities and allow refineries to take advantage of the improvements inherent in Appendix K versus the currently available leak detection and repair (LDAR) Alternative Work Practice (AWP) in Part 60 Subpart A (§60.18(g), (h) and (i)). Moreover, it would be important for EPA to amend other Part 60 and 63 standards to make Appendix K an option for industry sectors beyond refineries.*

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[107] 80 *Fed. Reg.* 75191 (December 1, 2015)

6.1.2 The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr) and either butane emissions of 5.0 g/hr or propane emissions of 18 g/hr at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less, unless the referencing subpart provides detection rates for a different compound(s) for that subpart.

Comment: *The response factor for butane and propane are almost identical, why has the agency selected lower mass rate criteria for butane? It seems inconsistent with the language in Section 1.2 which allows for the average response factor approach with respect to propane.*

9.3 The site must conduct monitoring surveys using a methodology that ensures that all the components regulated by the referencing subpart within the unit or area are monitored. This must be achieved using one of the following three approaches or a combination of these approaches. The approach(es) chosen and how the approach(es) will be implemented must be described in the monitoring plan

Comment: *The language provided in the Appendix K revisions for monitoring survey methodology provides additional flexibility consistent with industry comments. However, as written, the methodology is limited to just three options without any ability for a site to propose an alternative. Technology and survey approaches are always being improved with new creative ideas coming to forefront all the time. For example, use of GPS in surveys is only a recent capability in the past few years. The agency should add language which allows a site to use another methodology as long as it meets the intent and capabilities of the ones currently identified. A site could propose an alternative to their delegated authority prior to use*

9.4.1 For a complex scene of components, the operator must divide the scene into manageable subsections and dwell on each angle for a minimum of 2 seconds per component in the field of view (e.g., for a subsection with 5 components, the minimum dwell time would be 10 seconds). It may be necessary to reduce distance or change angles in order to reduce the number of components in the field of view

Comment: *See comments provided on “simple” and “complex” scene approaches.*

9.7.2 A full video of the monitoring survey must be recorded. The video must document the monitoring results for each piece of regulated equipment. Leaking components must be tagged for repair, and the date, time, location of each leak, and identification of the component associated with each leak must be recorded and stored with the OGI survey records.

Comment *– This language could be read to imply a full continuous video of the monitoring survey would be required which is inconsistent with the language of Section 9.7.1 where only video or still imagery of the leaks are required. This language should be deleted or clearly state that sites may elect as alternative to simply save the full continuous video versus leak imagery only.*

9.8 The monitoring plan must include a quality assurance (QA) verification video for each OGI operator at least once each monitoring day. The QA verification video must be a minimum of 5 minutes long and document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration.

***Comment** – As mentioned in previous comments to Appendix K proposals, the daily QA verification video is unlikely to offer much value to a monitoring program. The most effective methodology to ensure technician monitoring efficacy is comparative monitoring via periodic performance audits. The daily quality assurance (QA) verification video requirement should be deleted.*

10.2.2.1 A minimum of 3 survey hours with OGI where trainees observe the techniques and methods of a senior OGI camera operator (see definition in Section 3.0) who reinforces the classroom training elements.

10.2.2.2 A minimum of 12 survey hours with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and providing instruction/correction where necessary.

10.2.2.3 A minimum of 15 survey hours with OGI where the trainee performs monitoring surveys independently with a senior OGI camera operator trainer present and the senior OGI camera operator providing oversight and instruction/correction to the trainee where necessary.

***Comment:** The specific hourly requirement for each survey training phase is too restrictive and does not reflect how individuals learn and master new skills. Some technicians may need more or less time in a particular phase or benefit more from side-by-side or direct observation. A more appropriate approach is to specify a total of 30 hours of field survey hours which includes direct observation, side-by-side, and independent surveys without such prescriptive hourly content. As long as the 30 hours of training surveys includes an appropriate number of components to be surveyed (e.g., 300) and a final monitoring survey test, then the proficiency will be attained and verified.*

Attachment B

Comments on the U.S. Environmental Protection Agency's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

I. INTRODUCTION

As an addendum to our comments on the U.S. Environmental Protection Agency's ("EPA's" or "the Agency's") Supplemental Notice of Proposed Rulemaking on the revised "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" ("Proposed NSPS Revision"),[108] the American Petroleum Institute ("API") respectfully submits these additional comments on EPA's "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances" ("SC-GHG Report").[109]

API represents all segments of America's oil and natural gas industry. Our over 600 members produce, process, and distribute the majority of the nation's energy. The industry supports millions of U.S. jobs and is backed by a growing grassroots movement of millions of Americans. API was formed in 1919 as a standards-setting organization. In our first 100 years, API has developed more than 700 standards to enhance operational and environmental safety, efficiency, and sustainability. API and its members are committed to delivering solutions that reduce the risks of climate change while meeting society's growing energy needs. Addressing this dual challenge requires new approaches, new partners, new policies, and continuous innovation.

API believes that the pace of global action to reduce greenhouse gas ("GHG") emissions and effectively mitigate climate change will be determined by government policies and technology innovation. To that end, we have laid out a Climate Action Framework[110] that presents actions we are taking to accelerate technology and innovation, further mitigate GHG emissions from operations, advance cleaner fuels, drive comparable and reliable climate reporting, and, importantly, endorse a carbon price policy.

The natural gas and oil industry is essential to supporting a modern standard of living for all by ensuring that communities have access to affordable, reliable, and cleaner energy, and we are committed to working with local communities and policymakers to promote these principles across the energy sector. Our top priority remains public health and safety, and companies often have well-established policies in place for proactive community engagement and feedback aimed at fostering a culture of trust, inclusivity, and transparency. We believe that all people should be treated fairly, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

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[108] 87 Fed. Reg. 74,702 (Dec. 6, 2022).

[109] Docket ID No. EPA-HQ-OAR-2021-0317 (Sept. 2022).

[110] https://www.api.org/climate.

Indeed, API has for many years attempted to constructively engage the IWG in its development of SC-GHG estimates, and has submitted detailed comments on multiple previous IWG technical support documents, including the IWG's most recent "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" ("Interim TSD").[111] Those comments provided the IWG constructive and actionable recommendations to improve the transparency, rationality, defensibility, and thus, durability of its estimates of the SC-GHG, and urged caution on the inherently limited utility of SC-GHG estimates. Those comments also specifically recommended that the IWG publish proposals for, and accept public comment on, the recommendations the IWG was required to provide by September 1, 2021 regarding potential applications for the SC-GHG,[112] the additional recommendations the IWG was required to provide by June 1, 2022 for revising the processes and methodologies for estimating the SC-GHG,[113] and final SC-GHG estimates the IWG was supposed to publish "no later than January 2022."[114]

Insofar as API is aware, after publishing the interim SC-GHG estimates in 2021, the IWG has not completed any of the actions required by E.O. 13990 or taken any action in response to comments and recommendations submitted by API and other parties. Moreover, notwithstanding that EPA is a key participant in the IWG, EPA's unilateral development of the revised SC-GHG estimates in the SC-GHG Report is not only inconsistent with the approach President Biden committed to in E.O. 13990, it does not appear to reflect any consideration of the comments API and others provided to the IWG.

In the detailed comments that follow, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine ("National Academies" or "NASEM") provided to the IWG.

Although API appreciates EPA's willingness to accept comments on the SC-GHG Report, consistent with the National Academies' recommendations, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each modules had been updated and the SC-GHG Report had been fully drafted. Given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is insufficient for soliciting detailed feedback from informed stakeholders, particularly given that this comment period encompassed multiple holidays.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. This is a particular concern in a rulemaking conducted pursuant

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[111] 86 Fed. Reg. 24,669 (May 7, 2021).
[112] *See* 86 Fed. Reg. at 24,670.
[113] *See* E.O. 13990 at Sec. (5)(b)(ii)(D) and (E).
[114] *See* E.O. 13990 at Sec. (5)(b)(ii)(B).

to the Clean Air Act ("CAA" or "the Act") because of the CAA's enhanced requirement that EPA justify rules based solely on the record it compiles and makes public at the time of the proposal.[115]

Notwithstanding the forgoing, in Section III.b. below, API raises a number of significant technical questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. As noted therein, it is critical the SC-GHG Report completely and transparently explain the precise basis for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Finally, in Section III.c, API describes why, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. As EPA seemingly recognizes based on its apparent intent to use the SC-GHG Report in the Regulatory Impact Analysis but not as part of its assessment of the Best System of Emissions Reduction ("BSER") in the Proposed NSPS Revision itself, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.[116]

II. BACKGROUND

As noted in EPA's SC-GHG Report, the SC-GHG represents "the monetary value of future stream of net damages associated with adding one ton of that GHG to the atmosphere in a given year."[117] This metric, which originally attempted to estimate the social cost of only CO_2 emissions, "was explicitly designed for agency use pursuant to E.O. 12866. . ."[118] Since it was signed by President Clinton in 1993, E.O. 12866 has directed agencies to "propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs."[119] And when the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). Thus, the SC-GHG Report characterizes the SC-GHG as "the theoretically appropriate value to use when conducting benefit-cost analyses of policies that affect GHG emissions,"[120] and consistent with that characterization, EPA purports to only rely on the SC-GHG Report in the RIA it issued in support of the Proposed NSPS Revisions.[121]

Initially, federal agencies' consideration of CO_2 emissions in RIAs was sporadic and varied significantly between agencies.[122] When agencies did consider CO_2 emissions, they utilized a variety of different methodologies that

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[115] *See Sierra Club v. Costle*, 657 F.2d 298, 401 (D.C. Cir. 1981).

[116] *See* 87 Fed. Reg. at 74,713.

[117] SC-GHG Report at 4.

[118] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428. Per E.O. 12866 Sec. 1(a): "Federal agencies should promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling public need, such as material failures of private markets to protect or improve the health and safety of the public, the environment, or the well-being of the American people. . . . Further, in choosing among alternative regulatory approaches, agencies should select those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach."

[119] E.O. 12866 at Sec. 1(a). When the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). (E.O. 12866 at Sec. 6(a)(3)(C)). A "Significant regulatory action" is "any regulatory action that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in [E.O. 12866]" (Sec. 3(f)).

[120] SC-GHG Report at 4.

[121] *See* 87 Fed. Reg. at 74,713.

[122] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

resulted in a wide range of estimates, each with different ranges of uncertainty.[123] The government was consistent, however, in limiting use of these early estimates to RIAs, and in providing separate values for "domestic" and "global" impacts.[124] The government's consideration of CO_2 emissions became more frequent and consistent, however, after a 2008 Ninth Circuit decision remanded a fuel economy rule for failing to consider the potential benefit of CO_2 emission reductions, stating that "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero."[125] Subsequent court decisions on the necessity and method of considering CO_2 emissions for federal agency actions have been mixed.

To help federal agencies comply with E.O. 12866, "harmonize a range of different SC-CO_2 values being used across multiple Federal agencies,"[126] and "ensure consistency in how benefits are evaluated across agencies," President Obama established the IWG in 2009.[127] The IWG was tasked with developing "a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions."[128] As such, from the beginning, the IWG's SC-GHG estimates were intended to provide consistency across federal government agencies exclusively for the development of RIAs for "significant regulatory actions" involving GHG emissions. Notably, [t]his does not apply to many routine agency actions that will produce GHG emissions."[129]

The IWG's November 2013 TSD represented the first time the IWG (through OMB) accepted comment on the SC-CO_2 estimates.[130] Although the IWG and OMB had finally agreed to accept comments, they did not provide any materials other than the most recent TSDs. Thus, comments submitted by API and others urged the IWG to select its Integrated Assessment Model ("IAM") parameters through a highly transparent, collaborative, and data-driven process because modest changes to just a few model inputs drastically changes the output of the IAMs and therefore the SC-CO_2 estimate.[131]

The IWG broadly responded to the comments it received on the 2013 TSD in July 2015.[132] In that response, the IWG reiterated that the "purpose of [the IWG's] process was to ensure that agencies were using the best available information and to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions, or costs from increasing emissions, in regulatory impact analyses."[133]

The IWG updated its estimates of the SC-CO_2 again in August of 2016[134], and while API and others continued to have concerns with the transparency and rigor with which the IWG selected its model inputs, the TSD for the 2016 SC-CO_2 reflected some improvement to the characterization of uncertainty that was consistent with the NASEM Phase

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[123] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.
[124] Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (February 2020) ("2010 TSD) at 3.
[125] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1200 (9th Cir. 2008).
[126] 2021 TSD at 10.
[127] 2010 TSD at 4.
[128] 2010 TSD at 5.
[129] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.
[130] OMB's first-ever solicitation of public comment on the SC-CO_2 estimates was likely in response to a September 4, 2013 multi-association Petition for Correction filed under the Information Quality Act ("IQA") and numerous demands from Congress and other stakeholders for increasing the transparency of the SC-CO_2 estimation process.
[131] *See* multi-association comments filed February 26, 2014 (OMB-2013-0007-0140). OMB's July 2015 Response to Comments did not provide the key information sought by API and others, and resisted recommendations that the IWG select these parameters through a transparent process subject to peer review. (*See* July 2015 Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.) To its credit, however, OMB requested feedback from the NASEM on the IWG's process for updating the estimates of the SC-CO_2. (*See* NASEM 2017 at 1).
[132] Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (July 2015) ("2015 RTC").
[133] 2015 RTC at 3.
[134] 2016a TSD.

1 Report,[135] as well as API's prior comments. Notably, in an addendum to the 2016 TSD, the IWG adapted its SC-CO_2 methodology to estimate social costs for methane and nitrous oxide for the first time.[136] While the 2016 TSD represented the first time the IWG provided estimates of non-CO_2 GHG emissions, the IWG continued to represent that the purpose of the estimates was to allow agencies to consistently "incorporate the social benefits of reducing . . . emissions into cost-benefit analyses of regulatory actions."[137]

Months later, President Trump disbanded the IWG and instead directed each agency to develop their own SC-GHG estimates using the same IAMs and the IWG's same overall methodology for estimating the SC-GHGs.[138] As the U.S. Department of Justice explained in its June 4, 2021 brief in opposition to several states' motion to preliminarily enjoin Section 5 of E.O. 13990, and the interim SC-GHG values published under E.O. 13990:

> Although the Trump Administration's policy approach to climate issues differed in many ways from that of the preceding administration, it continued to use standardized estimates of the social costs of greenhouse gases. Pursuant to E.O. 13783, EPA developed interim SC-CO_2 estimates by making two (*and only two*) changes to the Working Group's 2016 estimates: First, it began reporting estimates that attempted to capture only the domestic impacts of climate change, and second, it applied 3% and 7% discount rates. . . . Accordingly, although the Working Group had been disbanded, and although the estimates of the social costs of greenhouse gas estimates were now lower (because of higher discount rates and an exclusive focus on U.S.-domestic damages), agencies continued to estimate the social costs of greenhouse gases in their cost-benefit analyses, as ordered by the President, just as they had done in prior administrations.[139]

While these two changes[140] were seemingly modest, their impact on the SC-GHG estimates, was anything but small. When the Obama Administration conducted its RIA for the Clean Power Plan ("CPP") in 2015, it estimated social costs of \$12, \$40, \$60, and \$120 per short ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 in 2011 dollars.[141] When the Trump Administration conducted its RIA for the review of the CPP in 2017, it estimated the SC-CO_2 to be \$6 per metric ton in 2020 (also in 2011 dollars) at the 3% discount rate, and \$1 at the 7% rate.[142]

> Thus, in the span of just two years, the same government agency, utilizing the 'best available science' put forth estimates for the same metric that had changed by so many orders of magnitude

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[135] National Academies of Sciences, Engineering, and Medicine 2016. *Valuing Climate Damages. Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on Near-Term Update*:. Washington, DC: The National Academies Press ("NASEM 2016").

[136] Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social cost of Methane and the Social Cost of Nitrous Oxide ("2016b TSD"). OMB did not request or receive the NASEM's feedback on the new estimates of the social costs of methane and nitrous oxide, nor were they subject to notice and comment, or peer reviewed. Rather, they were premised entirely on a U.S. Environmental Protection Agency ("EPA") employee's 2015 paper, which at that point had not been reviewed or published. (*See* Martin, A.L., Kopits, E.A., Griffiths, C.W., Newbold, S.C., and A Wolverton. 2015. Incremental CH_4 and N_2O Mitigation Benefits Consistent with the U.S. Government's SC-CO_2 Estimates. *Climate Policy* 15(2): 272-298).

[137] 2016 TSD at 3.

[138] *See* Executive Order 13783 (March 28, 2017) ("E.O. 13783").[138]

[139] *Missouri v. Biden*, 4:41-cv-00287 (E.D. MO 2021) (Page 11 of Defendants' June 4, 2021 Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction) (emphasis added).

[140] These changes flowed from E.O. 13783 ("when monetizing the value of changes in greenhouse gas emissions resulting from regulations, including with respect to the consideration of domestic versus international impacts and the consideration of appropriate agencies shall ensure, to the extent permitted by law, that any such estimates are consistent with the guidance contained in OMB Circular A-4.")

[141] U.S. EPA, EPA-452/R-15-03 Regulatory Impact Analysis for the Clean Power Plan (2015) at 4-2. (The four SC-CO2 estimates differ based on use of discount rates of 5%, 3%, 2.5%, and the ninety-fifth percentile distribution at the 3% discount rate. (See 4-6, 4-7).

[142] U.S. EPA, Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal (2017) at 44. The conversion factor for metric ton to short ton is approximately 0.91, such that these estimates were actually about 9% lower when compared to the Obama-era estimates (2017 CPP RIA at 44).

> as to be farcical. This was the case even though the Trump and Obama analyses utilized the same underlying models.[143]

Just a few years later, the IWG has republished the prior 2016 SC-GHG values as the new Interim SC-GHG estimates, and as instructed by E.O. 13990, these estimates "tak[e] global damages into account" and utilize discount rates that the IWG believes "reflect the interests of future generations in avoiding threats posed by climate change."[144] As a result, the Trump Administration's estimated SC-CO₂ values of $1 and $6 per metric ton in 2020 (in 2011 dollars)[145] increased to $14, $51, $76, and $152 per metric ton of CO₂ emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 (in 2020 dollars).[146]

This whipsawing of SC-GHG estimates is not based on any objective errors or omissions. Indeed, the IWG and Trump Administration can both point to academic scholarship and regulatory guidance in support of their selections of discount rates and geographic scales. Rather, these divergent estimates demonstrate the extent to which any given estimate of the SC-GHG differs based on one or two subjective judgements. The output of the models is dependent on subjective framing decisions that "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[147] And because many of the key analytical framing decisions that truly drove model output are subjective and not purely scientific determinations, robust and transparent stakeholder and public engagement is essential.

As API urged in its comments on the 2021 TSD and reiterates here, the sensitivity of SC-GHG modeling output to one or a few subjective inputs raises serious questions of the SC-GHG estimates' reliability and utility in rulemaking and policy analyses. It also illustrates the profound importance of adopting analytical framing decisions through a structured and predictable process that is open, transparent, and data-driven. While EPA may have valid reasons for unilaterally developing its own SC-GHG estimates, API is concerned that this unexplained deviation from the SC-GHG estimation and updating process that was historically consigned and recently re-entrusted to the IWG reflects another *ad hoc* estimation approach that lacks the necessary structure, consistency, and transparency.

Moreover, given that EPA's SC-GHG Report contains the most recent estimate of the SC-GHG provided by the federal government, API is concerned that other federal agencies may opt to rely on the estimates in the EPA's SC-GHG Report rather than the estimates in the IWG's 2021 Interim TSD. While this concern is somewhat mitigated by E.O. 13990's requirement that agencies use the IWG's values, the absence of any clear statement from EPA as to what the SC-GHG Report is or how its estimates are to be used perpetuates a serious concern that EPA's values may be misapplied in a variety of different regulatory and administrative contexts.

III. DETAILED COMMENTS

API is concerned about the procedures EPA employed when developing the SC-GHG Report and the revised estimates contained therein. We also have substantive technical questions and concerns about the methodology EPA employed in generating the revised SC-GHG estimates and the manner in which the Agency presented its

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[143] Taylor, A. (2018). Why the social cost of carbon is red herring. Tulane Environmental Law Journal, 31(2), 345-372 at 347.

[144] E.O. 13990 at Sec. 5(a) and 5(b)(iii).

[145] Using discount rates of 7% and 3%.

[146] Interim TSD at Table ES-1 (using discount rates of 5%, 3%, 2.5%, and the 95th percentile of the 3% discount rate)

[147] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 370. [T]hose who would consider inclusion of IAM-generated estimates, particularly high-dollar ones, of the SCC to be an unmitigated success should nonetheless pay heed to the crow on the shoulder: a high degree of arbitrariness is currently baked into these estimates and it is quite difficult to know the degree to which they may be relied upon for accuracy or manipulated by agencies across different administrations.

estimates in the SC-GHG Report. Finally, API believes that EPA should more fully and explicitly explain why the inherent limits of the SC-GHG estimates render them unsuitable for agency rulemaking and decisions that require the SC-GHG to be expressed as a single value or within a reasonably narrow range of uncertainty. The subsections that follow discuss each of these three broad areas of concern in detail.

a. Procedural Concerns

As President Biden noted in Executive Order 13990 ("E.O. 13990") on his first day in office, "[a]n accurate social cost is essential for agencies to accurately determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses . . ."[148] To that end, E.O. 13990 further instructed that, in undertaking actions such as developing SC-GHG estimates, "the Federal Government must be guided by the best science and be protected by processes that ensure the integrity of Federal decision-making.[149] Consistent with that mandate, President Biden also issued a Presidential Memorandum to all heads of executive departments and agencies reaffirming the Biden Administration's commitment to the principles outlined in President Clinton's Executive Order 12866 ("E.O. 12866")[150], which established the basic foundation for executive branch review of regulations, and President Obama's Executive Order 13563 ("E.O. 13563"),[151] which "took important steps toward modernizing the regulatory review process."[152]

Thus, through the Regulatory Review Memorandum, President Biden reaffirmed his administration's commitment to "allow for public participation and an open exchange of ideas;"[153] using "best available techniques to quantify anticipated present and future benefits and costs as accurately as possible;"[154] and ensuring "the objectivity of any scientific and technological information and processes used to support . . . regulatory actions."[155]

One week later, President Biden reiterated to his executive departments and agency heads that "[i]t is the policy of my Administration to make evidence-based decisions guided by the best available science and data."[156] According to the President Biden's Scientific Integrity Memorandum, "[w]hen scientific or technological information is considered in policy decisions, it should be subjected to well-established scientific processes, including peer review where feasible and appropriate. . ."[157]

API supports the principles President Biden outlined in these Executive Orders and presidential memoranda, and believes that certain aspects of EPA's development of SC-GHG estimates, such as taking public comment and committing to peer review, are broadly consistent with these principles. In other respects, however, EPA's development of the SC-GHG Report thus far appears to be the product of an insufficiently structured and transparent process.

Indeed, EPA's SC-GHG Report represents an unexplained departure from the more structured, transparent, and collaborative interagency process that the Biden Administration promised when it encouraged stakeholders

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[148] E.O. 13990 at Sec. 5.
[149] E.O. 13990 at Sec. 1.
[150] Signed Sept. 30, 1993.
[151] Signed Jan. 18, 2011.
[152] Memorandum for the Heads of Executive Departments and Agencies regarding "Modernizing Regulatory Review" (Jan. 20, 2021) ("Regulatory Review Memorandum").
[153] E.O. 13563 at Sec. 1(a).
[154] E.O. 13563 at Sec. 1(c).
[155] E.O. 13563 at Sec. 5.
[156] "Memorandum on Restoring Trust in Government Through Scientific Integrity and Evidence-Based Policymaking" Memorandum From President Biden to the Heads of Executive Departments and Agencies (Jan. 27, 2021) ("Scientific Integrity Memorandum"). *See also* Executive Order 14007, which establishes the President's Council of Advisors on Science and Technology. (Jan. 27, 2021) ("E.O. 14007).
[157] Scientific Integrity Memorandum preamble.

interested in the SC-GHG development process to engage with the IWG. EPA's SC-GHG Report reflects no consideration of the comments API and others submitted to the IWG, and the limited data and time that EPA has provided at this stage does not appear consistent with a strong Agency interest in soliciting critical analysis. Furthermore, EPA's curious solicitation of comments on the SC-GHG Report within an NSPS rulemaking, which does not utilize the SC-GHG Report, does not particularly reflect an interest in transparency and collaboration. In fact, EPA's equivocal and fluctuating descriptions of the SC-GHG Report make it impossible for the public to even understand why EPA drafted the SC-GHG Report in the first place, or how the Agency intends to use it.

1. Lack of Clarity Regarding What the SC-GHG Report is and how it will be used

In both the preamble to the Proposed NSPS Revisions and the RIA in EPA's docket for the Proposed RIA Revisions ("Docketed RIA"), EPA concludes that the IWG's "interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science."[158] Therefore, the Agency "estimated the climate benefits of methane emission reductions expected from this proposed rule using the social cost of methane (SC-CH_4) estimates presented in the [IWG's 2021 TSD]."[159]

Having disclaimed that the RIA estimated the climate benefits of the proposal's anticipated methane reductions using only the interim SC-GHG estimates from the IWG's 2021 TSD, EPA's preamble to the Proposed NSPS Revisions then describes the SC-GHG Report as "a sensitivity analysis of the monetized climate benefits using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine."[160] According to EPA's preamble, the RIA presents the results of the SC-GHG Report's screening analysis in "Appendix B of the RIA."[161] However, the Docketed RIA does not include the sensitivity analysis EPA described in the preamble, nor does it contain any reference to, or even mention of, the SC-GHG Report.

Earlier versions of the RIA that were exchanged between and edited by EPA, OMB, and other agencies reflect that the RIA previously contained a substantial discussion of the SC-GHG Report and also included EPA's new estimates from the SC-GHG Report in a sensitivity analysis in a then-designated Appendix B.[162] These aspects of the draft RIA were deleted in their entirety without explanation shortly before publication of the Proposed NSPS Revisions. However, and particularly problematic from the perspective of transparency in public engagement as well as EPA's docket and rulemaking requirements under CAA Section 307, the version of the RIA that EPA posted on its website for public comment on November 11, 2022 contains the subsequently deleted discussion of the SC-GHG Report and Appendix B sensitivity analysis.[163] Thus, EPA is presently soliciting comments on two strikingly different versions of the Draft RIA. Indeed, while it is beyond the scope of this appendix's specific focus on EPA's SC-GHG Report, the Agency's publication of two divergent Draft RIAs raises significant questions about the sufficiency of the notice-and-comment opportunity on the required E.O. 12866 analysis as well as the Proposed NSPS Revisions.

While EPA's last minute revisions to the RIA remain unexplained, what is clear from the Docketed RIA is that EPA's SC-GHG Report is not a sensitivity analysis, and that the report's revised SC-GHG estimates are not amenable for use in sensitivity analyses. EPA's "Sensitivity and Uncertainty Analyses: Training Module" describes a "sensitivity analysis" as "a method to determine which variables, parameters, or other inputs have the most influence on the

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[158] 87 Fed. Reg. at 74,843; Docketed RIA (EPA-HQ-OAR-2021-0317-0173) at 3-6.
[159] 87 Fed. Reg. at 74,713; *See also* 87 Fed. Reg. at 74,843; *See also* the RIA in EPA's docket for the Proposed NSPS Revisions at 3-6.
[160] 87 Fed. Reg. at 74,843.
[161] 87 Fed. Reg. at 74,714, Table 5, note b; *See also* 87 Fed. Reg. at 74,843.
[162] *See* Draft RIA revisions between September and November 2021 at EPA-HQ-OAR-2021-0317-1540,1541, 1542, 1543, 1544, 1545, 1546, 1548, 1573, 1574, 1575, and 1576.
[163] *See* https://www.epa.gov/environmental-economics/scghg.

model output."[164] Consistent with this description, EPA's Training Module explains that "[t]here can be two purposes for conducting a sensitivity analysis [1] comput[ing] the effect of changes in model inputs on the outputs; [2] to study how uncertainty in a model output can be systematically apportioned to different sources of uncertainty in the model input."[165]

EPA's SC-GHG Report and the SC-GHG estimates contained therein are in no way suited to these purposes. The estimates in EPA's SC-GHG Report were derived in a manner wholly different from the IWG's SC-GHG estimates. For each of the four modules of the SC-GHG estimation process - socioeconomics and emissions, climate, damages, and discounting – EPA's SC-GHG Report uses different models, methodologies, analytical framing decisions, and data than the IWG utilized. As detailed in the Executive Summary to the SC-GHG Report:

> The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future Social Cost of Carbon Initiative . . . The climate module relies on the Finite Amplitude Impulse Response (FaIR) model… The socioeconomic projections and outputs of the climate module are used as inputs to the damage module to estimate monetized future damages from temperature changes. Based on a review of available studies and approaches to damage function estimation, the report uses three separate damage functions to form the damage module. They are: 1. a subnational-scale, sectoral damage function… 2. a country-scale, sectoral damage function… and 3. a meta-analysis-based damage function… The discounting module . . . us[es] a set of dynamic discount rates that have been calibrated following the Newell et al. (2022) approach, as applied in Rennert et al. (2022a, 2022b). … Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates. … Finally, the value of aversion to risk associated with damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. The estimation process generates nine separate distributions of estimates – the product of using three damage modules and three near-term target discount rates – of the social cost of each gas in each emissions year. To produce a range of estimates that reflects the uncertainty in the estimation exercise while providing a manageable number of estimates for policy analysis, in this report the multiple lines of evidence on damage modules are combined by averaging the results across the three damage module specifications.[166]

Every aspect of the above-described estimation process differs from the process employed by the IWG. And, because every aspect of EPA's SC-GHG estimation process differed from the IWG's process, it does not allow EPA "to determine which variables, parameters, or other inputs" in the IWG's estimation process "have the most influence on the model output." Examining two wholly different estimation processes does not provide any basis to discern how any of the IWG's inputs may impact the IWG's model output or apportion uncertainty to the IWG's various inputs.

"Sensitivity analyses" require the isolation and examination of one or a few model inputs while all other model parameters remain constant. For instance, in the 2021 TSD, the IWG advised that "agencies may consider

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[164] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).

[165] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).

[166] SC-GHG Report at 1-2.

conducting additional sensitivity analysis using discount rates below 2.5 percent."[167] Consistent with EPA's Training Module and standard practices for conducting sensitivity analyses, the IWG instructed that agencies' sensitivity analyses should isolate a single input (the discount rate) in order to assess the impact of changes from that single input on the model output.

The estimates in EPA's SC-GHG Report are simply new estimates based on new methods and data, and they therefore plainly have no value in any scientifically relevant sensitivity analysis. Indeed, what EPA deemed a "Screening Analysis" in the since-deleted sections of the Docketed RIA was not a screening analysis at all, at least as defined by EPA's Training Module. EPA merely compared the values from the IWG's 2021 TSD to EPA's SC-GHG Report and found that the benefits estimated in EPA's SC-GHG Report were higher than the IWG's 2021 interim estimates. This is truly the full extent of EPA's use of the SC-GHG Report for a "sensitivity analysis," which perhaps explains the Agency's decision to strike those references from the Docketed RIA.

Recognizing that neither EPA's SC-GHG Report nor the estimates contained therein constitute, or can credibly be used in sensitivity analyses, one is compelled to recognize the SC-GHG Report's estimates for what they are – SC-GHG values that are wholly separate and distinct from the 2021 IWG interim SC-GHG estimates that the Biden Administration directed all agencies to use. In fact, the SC-GHG Report itself never suggests its estimates are intended or even suitable for sensitivity analyses. The SC-GHG Report accurately describes them as "new estimates of the SC-GHG."[168]

Indeed, the SC-GHG Report's estimates are "new estimates of the SC-GHG," but given EPA's deletion of the supposed "sensitivity analysis" and assertion that the SC-GHG Report's estimates were not used in the RIA or the "statutory [best system of emissions reduction] determinations" in the Proposed NSPS Revisions,[169] commenters are left with no explanation why EPA developed the SC-GHG Report, how EPA intends to use the report's estimates, or why EPA included the SC-GHG Report in the docket for the Proposed NSPS Revisions. A truly transparent and collaborative process demands much more than this. EPA should provide a full and complete explanation for the development and intended use of the SC-GHG Report before subjecting it to peer review or public comment. Absent any explanation of the SC-GHG Report's intended use, reviewers have little basis to opine on its suitability.

2. Inconsistency with the Biden Administration's Stated Approach to the SC-GHG

From the earliest days of his Administration and consistently thereafter, President Biden and other Administration officials publicly committed to developing and updating government-wide SC-GHG estimates through the IWG by prescribing a detailed and incremental process. Based on the Administration's representations, API and other stakeholders devoted significant time and resources attempting to engage the IWG, but the rigorous and transparent IWG process that the Biden Administration promised has not yet materialized in any meaningful way. Now, more than two years after the IWG released its first and only publication of the several it had been charged with developing, EPA appears to be charting its own course by developing its own agency-specific SC-GHG estimates in the SC-GHG Report.

As discussed in more detail below, EPA's independent development of SC-GHG estimates is incompatible with and, in fact, undermines the unified approach promised by the Biden Administration in E.O 13990. We also describe

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[167] 2021 TSD at 4; *See also* 2021 TSD at 21 ("the IWG finds it appropriate as an interim recommendation that agencies may consider conducting additional sensitivity analysis using discount rates below 2.5%.").
[168] SC-GHG Report at 84.
[169] 87 Fed. Reg. at 74,843.

why EPA's unilateral SC-GHG estimates and any subsequent proliferation of agency-specific SC-GHG estimates contravene the Administration's stated interest in assessing the benefits and costs of proposed regulations consistently and cohesively across all federal agencies.

i. President Biden's Promised Approach for the Development and Agency use of SC-GHG Estimates

After the Trump Administration disbanded the IWG, President Biden on his first day in office issued E.O. 13990, which reestablished the IWG as the federal entity charged with developing and publishing the SC-GHG estimates that are to be used by all federal agencies.[170] The IWG's mission is fivefold:

> (A) publish an interim [SC-GHG] within 30 days of the date of this order, which agencies shall use when monetizing the value of changes in greenhouse gas emissions resulting from regulations and other relevant agency actions until final values are published;
>
> (B) publish a final [SC-GHG] by no later than January 2022;
>
> (C) provide recommendations to the President, by no later than September 1, 2021, regarding areas of decision-making, budgeting, and procurement by the Federal Government where the [SC-GHG] should be applied;
>
> (D) provide recommendations, by no later than June 1, 2022, regarding process for reviewing, and, as appropriate, updating, the [SC-GHG] to ensure that these costs are based on the best available economics and science; and
>
> (E) provide recommendations, to be published with the final [SC-GHG] under subparagraph (A) if feasible, and in any event by no later than June 1, 2022, to revise methodologies for calculating the [SC-GHG], to the extent that current methodologies do not adequately take account of climate risk, environmental justice, and intergenerational equity.[171]

Insofar as API is aware, the IWG has only completed the first of the five tasks prescribed by E.O. 13990.[172] Regarding these interim estimates, the E.O. mandates that "agencies ***shall*** use" them in promulgating their own "regulations and other relevant agency actions until final values are published."[173] Thus, although it is unclear why EPA developed the SC-GHG Report and how the Agency intends its SC-GHG estimates to be used, it bears mentioning that agencies deviating from these interim estimates do so in contravention with E.O. 13990.

The requirements of E.O. 13990 are also memorialized in the 2021 Interim TSD, which describes President Biden's directive that the reconstituted IWG "ensure that SC-GHG estimates used by the U.S. Government (USG) reflect the best available science and the recommendations of the National Academies (2017)…"[174] Consistent with the Executive Order, the IWG plainly recognized that the SC-GHG estimates it developed were to be used throughout the "U.S. Government," unless expressly precluded by statute.[175]

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[170] E.O. 13990 at Sec. 5.

[171] E.O. 13990 at Sec. 5(b)(ii).

[172] 2021 TSD.

[173] E.O. 13990 at Sec. 5(b)(ii)(a) (emphasis added).

[174] 2021 TSD at 3.

[175] Social Cost of Greenhouse Gas Emissions: Frequently Asked Questions (FAQs), ("OIRA Guidance") at 2, June 3, 2021. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/Social-Cost-of-Greenhouse-Gas-Emissions.pdf.

The IWG's Interim TSD goes on to instruct that the Interim SC-GHG estimates "should be used by agencies until a comprehensive review and update is developed in line with the requirements in E.O. 13990."[176] The Interim TSD also "determined that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates (2.5 percent, 3 percent, and 5 percent) as were used in regulatory analyses between 2010 and 2016 and subject to public comment."[177]

OMB, the entity responsible for coordinating the IWG efforts,[178] has likewise confirmed that President Biden's reconstitution of the IWG demonstrates that the President intended the IWG alone develop the SC-GHG estimates necessary "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[179] This directive is further confirmed in the June 2021 guidance document OIRA issued to agencies to assist in applying Section 5 of E.O. 13990.[180] The OIRA Guidance clarified that "[p]ursuant to E.O. 13990, when agencies prepare an assessment of the potential costs and benefits of regulatory action for purposes of compliance with E.O. 12866, they *must* use the 2021 interim estimates in monetizing increases or decreases in greenhouse gas emissions that result from regulations and other agency actions until updated values are released by the IWG."[181] Accordingly, E.O. 13990, the 2021 Interim TSD, OMB's solicitation of comments on the Interim TSD, and OIRA's guidance not only directed federal agencies to use the IWG's SC-GHG estimates, they apprised stakeholders interested in the federal government's SC-GHG estimates that the IWG was the sole entity with which to engage regarding the development of these important values.

In litigation surrounding E.O. 13990 and the 2021 Interim TSD, the U.S. Department of Justice ("DOJ") also describes the Biden Administration's stated approach to developing and using SC-GHG estimates, and opined on the degree to which E.O. 13990 compelled agencies to use the IWG's values:

> … the Executive Order requires agencies to use the Interim Estimates in some circumstances. *See* E.O. 13990 §§ 5(b)(ii)(A) (using the word "shall"); OIRA Guidance, at 1. But that directive is inoperative whenever the agency faces any conflicting statutory obligation . . .In other words, agencies will only ever rely on the Interim Estimates when they have discretion to do so…[182]

As DOJ stated elsewhere even more succinctly, "if an agency undertakes [SC-GHG] monetization, it shall use the Interim Estimates rather than another set of figures."[183]

ii. EPA's SC-GHG Report Contravenes the Approach President Biden Promised Stakeholders

Although it is not yet clear how EPA intends to use the estimates in its SC-GHG Report, the Agency's development and publication of these values appears to conflict with President Biden's explicit directive that the IWG develop the federal government's SC-GHG estimates and that federal agencies use those estimates. The Administration assigned this centralized role to the IWG "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[184] Even though EPA is a key member of the IWG and EPA's staff certainly

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[176] 2021 TSD at 4.
[177] 2021 TSD at 4.
[178] *See* E.O. 13990 at Sec. 5; *See also* 86 Fed. Reg. at 24,669.
[179] 86 Fed. Reg. at 24,669.
[180] *See* OIRA Guidance.
[181] OIRA Guidance at 1.
[182] Defendants' Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction, Page 23, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).
[183] Brief for Appellees, Page 40, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).
[184] 86 Fed. Reg. at 24,669.

have a high level of expertise in climate science and economic analysis, E.O. 13990's reestablishment of the IWG seems to indicate that the Biden Administration believed that development of the highly important SC-GHG estimates called for a breadth of expertise and diversity of opinions unlikely to be found within a single agency.

While API has often disagreed with the IWG's lack of transparency and with various modeling decisions and methodologies that the IWG has employed in developing SC-GHG estimates, we believe that the multi-agency composition of the IWG provides at least an opportunity to develop future SC-GHG estimates using a greater diversity of viewpoints and expertise. Thus, when the Biden Administration once again consigned the federal government's SC-GHG estimation process to the IWG, API once again devoted significant time and resources developing comments reflecting our own viewpoints and considerable expertise. Unfortunately, the IWG's unexplained inaction on the tasks it was assigned in E.O. 13990 along with EPA's unilateral development of SC-GHG estimates in contravention with E.O. 13990 seem to indicate that API's efforts to engage the IWG may have been in vain and that the process laid out in E.O. 13990 has been inexplicably abandoned.

API and others with a deep interest in, and credible expertise relevant to, the development of SC-GHG estimates are effectively precluded from meaningfully engaging with the federal government on these estimates if the Administration changes without explanation the entities, planned actions, and procedures for developing SC-GHG estimates.

The other reason the Administration re-established the IWG and tasked it with developing the SC-GHG estimates was "to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions in regulatory impact analyses."[185] This accords with OMB Circular A-4, which emphasizes that "[i]n undertaking [benefit-cost analysis and cost-effectiveness analysis], it is important to keep in mind the larger objective of analytical consistency in estimating benefits and costs *across regulations and agencies*, subject to statutory limitations."[186]

While we recognize that the Administration has announced its intent to revise Circular A-4,[187] the mere prospect of these revisions provides no basis for contravening the guidelines and instructions currently provided by Circular A-4. Unless and until Circular A-4 is revised or replaced, it should continue to guide EPA and other agencies to develop clear, transparently supported, objective, and consistent RIAs. Indeed, far from justifying any departures from Circular A-4's guidelines, the Administration's announcement that Circular A-4 will be revised further illustrates that EPA's unilateral development of SC-GHG estimates is inconsistent with the overall RIA and SC-GHG development framework that the Biden Administration publicly announced.

Finally, the need for a single consistent process for developing the SC-GHG estimates used in RIAs is further reflected in a 2020 Government Accountability Office ("GAO") Report on the SC-GHG and specifically the manner in which the federal government should address the recommendations of the National Academies."[188] Recognizing that the National Academies' recommended procedural and technical improvements could not be feasibly implemented by a multitude of different agencies, the GAO urged OMB to "identify a federal entity or entities to be responsible for addressing the National Academies' recommendations…"[189] GAO considered the recommendation "implemented" when E.O. 13990 reinstated the IWG.[190]

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[185] 2021 TSD at 10.

[186] OMB Circular A-4, Pages 9-10 (emphasis added).

[187] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.

[188] GAO-20-254, Report to Congressional Requesters, SOCIAL COST OF CARBON: Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis ("GAO-20-254").

[189] GAO-20-254.

[190] GAO-20-254 Recommendation Status, https://www.gao.gov/products/gao-20-254#summary_recommend.

Thus, EPA's unexplained deviation from the SC-GHG development approach laid out in E.O. 13990 not only upends the process to which API and other have devoted time and resources, it undermines the federal government's longstanding objective of making RIAs more consistent across agencies and detracts from what the GAO and this Administration identified as necessary to improve the SC-GHG estimation process consistent with the National Academies' recommendations.

3. Failure to Respond to Comments

As a further consequence of the Agency's decision to unilaterally develop its own SC-GHG estimates, EPA's SC-GHG Report does not appear to be based on any meaningful consideration of the many significant and detailed comments submitted to the IWG, including most recently, the many comments in response to the 2021 Interim TSD. Based on the Biden Administration's representation that the IWG alone would develop the SC-GHG estimates that would be used by the many agencies of the federal government, "[t]he Office of Management and Budget (OMB), on behalf of the cochairs of the Interagency Working Group on the Social Cost of Greenhouse Gases, including the Council of Economic Advisors (CEA) and the Office of Science and Technology Policy (OSTP)," requested "public comment on the interim TSD as well as on how best to incorporate the latest peer-reviewed science and economics literature in order to develop an updated set of SC–GHG estimates."[191]

Notwithstanding that the IWG purported to solicit public comments "in order to facilitate early and robust interaction with the public on this key aspect of this Administration's climate policy,"[192] neither the IWG nor EPA, which is a key member of the IWG, ever responded to or meaningfully considered the public comments submitted by API and many others in 2021. This does not represent a valid and transparent effort to engage the public and solicit feedback to improve agency decision-making.

"For an agency's decisionmaking to be rational, it must respond to significant points raised during the public comment period."[193] EPA is not relieved of this obligation simply because the comments were solicited by OMB on behalf of the IWG. As a key member of the IWG, EPA "reviewed the comments submitted to the IWG,"[194] and therefore had an obligation to "engage the arguments raised before it."[195]

The issues on which the IWG solicited comment, including advances in science and economics, approaches for implementing the National Academies' recommendations, approaches for intergenerational equity, and the use of discount rates,[196] are directly relevant to the EPA's SC-GHG Report. So too are the significant comments and data submitted by API and others in response to the IWG's solicitation.

In particular, API submitted detailed and constructive questions and comments on issues regarding the selection of discount rates, the ability to reasonably forecast impacts on expansive time horizons, and the importance of providing domestic SC-GHG values alongside global values. The IWG never responded to these comments and questions, and given the existence of these same concerns in EPA's SC-GHG Report, EPA plainly ignored API's comments as well.

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[191] 87 Fed. Reg. 24,669 (May 7, 2021).
[192] 87 Fed. Reg. at 24,670.
[193] *Allied Local & Reg'l Mfrs. Caucus v. EPA,* 215 F.3d 61, 68 (D.C. Cir. 2000).
[194] SC-GHG Report at 8.
[195] *Del. Dep't of Nat. Res. & Envtl. Control v. EPA*, 785 F.3d 1, 11 (D.C. Cir. 2015); *see Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 214 (D.C. Cir. 2013).
[196] 87 Fed. Reg. at 24,670.

It is not enough for EPA to suggest that it "has reviewed the comments submitted to the IWG in developing [the SC-GHG Report]."[197] EPA must respond in a reasoned manner to the comments received, [] explain how the agency resolved any significant problems raised by the comments, and [] show how that resolution led the agency to [its conclusion]."[198] "Consideration of comments as a matter of grace is not enough.' It must be made with a mind open to persuasion."[199]

It is also insufficient that EPA is now accepting comment on the SC-GHG Report. To begin, EPA's acceptance of comments on entirely new SC-GHG estimates in a wholly distinct SC-GHG Report in no way mitigates the absence of any record that EPA meaningfully engaged with or responded to any of the comments already submitted to the IWG.

Further, while it remains unclear what the SC-GHG Report is or how EPA intends to use it, nowhere does EPA represent that the report is in draft form or that the Agency will revise the SC-GHG Report based on comments and data received. On the contrary, EPA states that the "report presents new estimates of the SC-GHG" that EPA may rely upon "while [the IWG] process continues."[200] Therefore, if EPA intends to use and rely on the values in the SC-GHG Report as they are currently estimated, the Agency's solicitation of comments at this point does not truly "allow for public participation and an open exchange of ideas."[201] Nor is such an approach consistent with the National Academies' recommendation that draft revisions to the SC-GHG methods and estimates should be subject to public notice and comment, allowing input and review from a broader set of stakeholders, the scientific community, and the public.[202]

4. <u>EPA has not Provided Interested Parties the Time or Information Necessary to Solicit Detailed and Constructive Feedback</u>

In order for its public comment process to be reasonable and therefore lawful, EPA must provide commenters access to the data, studies, and other records on which the Agency relied as well as reasonably adequate time to review the data and draft comments analyzing EPA's conclusions and findings based on those records. EPA's present solicitation of comments on the SC-GHG Report does not satisfy either of these requirements.

The U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") makes clear that when an agency relies on data that is critical to its decision-making process, that data must be disclosed in order to provide the public an opportunity to meaningfully comment on the agency's rulemaking rationale.[203] Indeed, the D.C. Circuit has consistently maintained that "[i]n order to allow for useful criticism it is especially important for the agency to identify and make available *technical studies and data* that it has employed in reaching the decisions to propose particular rules."[204]

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[197] SC-GHG Report at 8.

[198] *Indep. U.S. Tanker Owners Comm v. Lewis*, 690 F.2d 908, 919 (D.C. Cir. 1982).

[199] *Advocates for Hwy & Auto Safety v. Fed. Hwy. Admin*., 28 F.3d 1288, 1292 (D.C. Cir. 1994) (citing *McLouth Steel Products Corp. v. Thomas*, 838 F2d 1317, 1323 (D.C. Cir. 1988)).

[200] SC-GHG Report at 84.

[201] E.O. 13563 at Sec. 1(a).

[202] National Academies of Sciences, Engineering, and Medicine 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*: Washington, DC: The National Academies Press ("NASEM 2017") at Pages 58-60.

[203] *See, e.g., Conn. Light & Power Co. v. Nuclear Regulatory Comm'n,* 673 F.2d 525, 530 (D.C. Cir. 1982); *Chamber of Commerce v. SEC,* 443 F.3d 890, 899 (D.C. Cir. 2006); *Am. Radio Relay League, Inc. v. FCC,* 524 F.3d 227, 236-37 (D.C. Cir. 2008).

[204] *Conn. Light & Power Co.,* 673 F.2d at 530 (emphasis added); *See also Am. Radio Relay League, Inc.,* 524 F.3d at 237 ("It would appear to be a fairly obvious proposition that studies upon which an agency relies in promulgating a rule must be made available during the rulemaking in order to afford interested persons meaningful notice and an opportunity for comment.").

Moreover, because of the "complex scientific issues involved in EPA rulemaking" Congress established more rigorous requirements under the CAA for making information available for public scrutiny.[205] Hence, the CAA mandates that "[a]ll data, information, and documents . . . on which the proposed rule relies *shall* be included in the docket on the date of publication of the proposed rule."[206] This critical requirement is particularly relevant here because EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, which is a rulemaking pursuant to the CAA.[207]

Therefore, if "documents of central importance upon which EPA intended to rely had been entered in the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."[208] "The Congressional drafters, after all, intended to provide 'thorough and careful procedural safeguards . . . [to] insure an effective opportunity for public participation in the rulemaking process.'"[209]

Notwithstanding this requirement, EPA's docket omits several studies, records, and other materials that appear fundamental to the Agency's development of the SC-GHG Report. For instance, EPA claims to have based several aspects of the SC-GHG Report on "the public comments received on individual EPA proposed rulemakings and the IWG's February 2021 TSD,"[210] but only identifies two supportive comments of the 88 total comments submitted on the 2021 TSD.[211] EPA did not identify or provide any comments "it received on individual EPA proposed rulemakings." Therefore, the Agency's administrative record for the SC-GHG Report is either insufficiently comprehensive or EPA impermissibly "rel[ied] on some comments while ignoring comments advocating a different position."[212]

Similarly, the SC-GHG Report relies extensively on SC-GHG estimation and modeling approach developed by RFF,[213] but while EPA's administrative record includes the RFF paper itself, it does not include all the data and studies that RFF utilized in developing those projections and estimates that EPA incorporated into its SC-GHG Report. For instance, RFF augments their economic forecast and generates their emissions forecast based on expert opinion,[214][215] but EPA's administrative record does not appear to contain any details or documentation regarding the expert elicitation and forecasting that was a key part of RFF's modeling effort. Given the critical importance of these forecasts in modelling the SC-GHG and EPA's implicit adoption of the forecasts in the SC-GHG Report, EPA should provide the public with details regarding how and why these experts were selected. For example, EPA should submit for public comment in the docket for the Proposed NSPS Revisions RFF's documentation, which details RFF's survey methodologies, partial selection methodology, and results. EPA should also extend the time period for submission of public comments on EPA's SC-GHG Report. Additionally, EPA should foster transparency by clarifying how RFF selected their experts from RFF's nominee pool.

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[205] *E.g., Small Ref. Lead Phase-Down Task Force v. EPA,* 705 F. 2d 506, 518 (D.C. Cir. 1983).

[206] CAA § 307(d)(3) (emphasis added); *see Kennecott Corp. v. EPA,* 684 F. 2d 1007, 1018 (CAA § 307(d)(3) requires EPA to place in the docket "the factual data on which the proposed regulations are based").

[207] 87 Fed. Reg. at 74,713.

[208] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (D.C. Cir.1981); *See also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C.Cir. 1982) (EPA improperly placed economic forecast data in the record only one week before issuing its final regulations).

[209] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (citing H.R.Rep.No.95-294, 95th Cong., 1st Sess. 188 at 319 (1977)).

[210] SC-GHG Report at 26, 37, 53, and 8.

[211] SC-GHG Report at 14 (FN26), and 15 (FN37).

[212] *National Women's Law Center v. Office of Management and Budget*, 358 F. Supp. 3d 66, 91 (D.D.C. 2019).

[213] Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. Brookings Papers on Economic Activity. Fall 2021, pp.223-305.

[214] Rennert et al.'s economic growth survey included the following participants: Daron Acemoglu, Erik Brynjolfsson, Jean Chateau, Melissa Dell, Robert Gordon, Mun Ho, Chad Jones, Pietro Peretto, Lant Pritchett, and Dominique van der Mensbrugghe.

[215] Rennert et al.'s future emissions survey included the following participants: Sally Benson, Geoff Blanford, Leon Clarke, Elmar Kriegler, Jennifer Faye Morris, Sergey Paltsev, Keywan Riahi, Susan Tierney, and Detlef van Vuuren.

More fundamentally, as discussed in Section III.a.1, EPA's administrative record does not even sufficiently apprise the public as to why EPA developed the SC-GHG Report or how the Agency intends to use it. However, even if EPA had timely provided all of the documents of central importance upon which it relied in drafting the SC-GHG Report, the public comment period EPA provided remains woefully insufficient. The SC-GHG Report provides a completely new set of SC-GHG estimates that were generated through a substantially revised modular approach using entirely different methodologies, models, studies, data, and analytical framing decisions than have been used by the IWG. And while EPA has not populated the administrative record with the full universe of the centrally important records on which it relied, there are hundreds of sources cited in the SC-GHG Report and the RFF Study that provided significant portions of the analysis used in the SC-GHG Report. As evidenced by the five years it took RFF to develop its SC-GHG estimates[216] and the fact that the IWG is more than a year overdue in developing the final SC-GHG estimates required by E.O. 13990, reviewing SC-GHG estimates and their underlying methodologies and data is incredibly labor-intensive and time-consuming.

As such, EPA's decision to provide the public only 69 days to review, develop, and submit comments on the SC-GHG Report is plainly unreasonable – particularly so, given that the comment period coincided with the holiday season. EPA's comment deadline for the SC-GHG Report is also unreasonable because it is the same comment period through which EPA is soliciting comments on the Proposed NSPS Revisions. The proposed revisions are complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under the CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, the current comment deadline is insufficient for even the Proposed NSPS Revisions alone.

In sum, EPA's current administrative record and comment deadline for the SC-GHG Report do not reasonably "allow for public participation and an open exchange of ideas."[217] API therefore respectfully requests that EPA supplement the administrative record with all of the centrally relevant information EPA utilized in developing the SC-GHG Report and provide a new and substantially longer comment period focused exclusively on the SC-GHG Report and the estimates contained therein.

b. <u>Technical Issues with EPA's Methodology and Presentation of the SC-GHG Estimates</u>

In addition to the procedural issues API described in the preceding subsection, our review of the SC-GHG Report raised several significant questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. It is critical the SC-GHG Report completely and transparently explain the precise bases for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Moreover, given the enormous and continually growing body of data and academic literature relevant to estimating the SC-GHG, the process by which EPA selects the data and literature on which it relies must be rigorous, objective, and transparent. Thus, when describing the evidentiary bases for its SC-GHG estimates, the SC-GHG Report should not only identify the studies on which the Agency relied, it must reasonably explain and describe why EPA declined to utilize other credible academic literature and data.

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[216] https://www.resources.org/archives/the-social-cost-of-carbon-reaching-a-new-estimate/?_gl=1*becwm3*_ga*OTczMDg2OTQzLjE2NzQ3NTAyOTI.*_ga_HNHQWYFDLZ*MTY3NDg0OTI4Ny4yLjEuMTY3NDg0OTMyMi4wLjAuMA.

[217] E.O. 13563 at Sec. 1(a).

The bullets below briefly describe a number of the questions and concerns that API and its members raised after reviewing the SC-GHG Report. Given the constrained timeframe for review and comment, these questions and concerns should by no means be considered exhaustive or complete. Rather, we urge EPA to view these questions and concerns as emblematic of API's broader concern with the manner in which the SC-GHG Report describes and supports EPA's model choices and SC-GHG estimation process.

- **Damage functions** – Two of the damage functions used in EPA's new SC-GHG model estimate damages at a subnational and/or sectoral level. However, there is no discussion about why EPA excluded other damage functions, particularly those produced by structural economy-wide models.[218] EPA should identify all the possible damage function approaches that could be incorporated and discuss the relative merits and shortcomings of each so stakeholders can understand EPA's rationale for their selected approach.

  Furthermore, given the relative importance of mortality-related impacts in the two sectoral damage functions, EPA should place more attention on how response functions could be adjusted for differences in age distributions across regions. Carleton *et al.* 2020 demonstrated that the temperature-mortality response function differs substantially by age, with a particularly strong relationship observed in the 65+ population. While age is included as a covariate in some of the studies included in Cromar *et al.* 2022, it is not uniformly considered across the literature assessed there. For example, the studies that do adjust for age do not present full mortality results by age. Cromar *et al.* did not consider heterogeneity by age group in their models estimating future mortality associated with temperature changes even though some of the individual studies included in Cromar *et al.* accounted for age. The ideal temperature-mortality model and subsequent monetization would account for age group heterogeneity at all stages of the analysis and calculations.

  Additionally, the temperature-mortality function for a given location and population will likely change through implementation of adaptation measures, a critical consideration in the SC-GHG estimation for mortality. However, adaptation is not consistently incorporated into these studies; and those studies that include adaptation vary in the way it is incorporated. In Carleton *et al.* 2020, administrative level 2 gross domestic product ("GDP") per capita and mean annual temperature for each location incorporates adaptation such that the location-specific exposure-response curve accounts for heterogeneity in adaptation response. Cromar *et al.* did not incorporate adaptation measures at a global or region-specific level, despite stating the importance of incorporating adaptation. As these measures will vary by many factors, including the regional climate and socioeconomic status, it is important that any future projections of the temperature-mortality function account for potential adaptation to temperature change, and the ideal study would account for adaptation at the local level.

- **Discount rate** – There are several choices regarding the discount rate that deserve more consideration and discussion. First, EPA should more fully justify its claim that long-term structural breaks in the interest rate imply lower interest rates in the future.[219] EPA should also explain how near-term interest rates from the last thirty years can fully inform the choice of an appropriate discount rate for the SC-GHG given the projection horizon of 300 years. Other work[220] has considered interest rates over long-time horizons and disputed the notion of structural breaks which calls into question some of EPA's discount rate assumptions. Furthermore, EPA should

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[218] Rose, S, D Diaz, T Carleton, L Drouet, C Guivarch, A Méjean, F Piontek, 2022. Estimating Global Economic Impacts from Climate Change. In Climate Change 2022: Climate Impacts, Adaptation, and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the IPCC, Chapter 16.

[219] *See* SC-GHG Report at 59.

[220] Rogoff et al. 2022. Long-Run Trends in Long-Maturity Real Rates 1311-2021. National Bureau of Economic Research.

explain their rationale for using a single discount rate for all regions, given that certain parameters used to estimate it, such as the economic growth rate, clearly vary across regions.

Second, since EPA estimates Ramsey parameters using assumptions about these near-term interest rates, EPA should consider whether the implied Ramsey parameters are reasonable and consistent with other available information. For example, the pure rate of time preference (ρ) that EPA estimates under the 2 percent near-term discount rate (0.2 percent) is significantly lower than those found in the Drupp *et al.*[221] survey cited in the SC-GHG Report.[222] Moreover, the value of ρ under the 1.5 percent near-term discount rate is near-zero, even though as EPA notes "it has been argued that very small values of ρ can lead to an unreasonable rate of optimal savings (Arrow et al. 1995), particularly with η around 1 (Dasgupta 2008, Weitzman 2007)."[223] Such results further call into question the choice of near-term discount rates and the reasons why parameters such as the Ramey parameters were forced to accommodate particular near-term discount rates, rather than the opposite.

Third, related to the calibration, EPA should state and explain how it calculates the near-term real growth rate of consumption per capita (g_t) as this is one of the few elements within the Ramsey discount rate that is observable in the market. To recover EPA's Ramsey parameters, a near-term consumption per capita growth rate of around 1.45 percent would seemingly be needed. Given that EPA appears to use the GDP per capita growth rate as a proxy for the consumption per capita growth rate, it is unclear why EPA derives its consumption per capita rate as the EPA notes "in the past decade average global per capita growth rates have been closer to 2%,"[224] and over the longer term global per capita growth rates have been higher. Once again, such results call into question why the growth rate was forced to accommodate other assumptions, rather than the opposite, given that the growth rate is the most observable of all the terms in the Ramsey equation.

Fourth, EPA should clarify how it estimates the near-term consumption growth rate "net of baseline climate change damages," and provide a practical example of how it calculated the consumption growth rate "net of baseline climate change damages" beyond what is offered in Appendix 3 of the SC-GHG Report. Moreover, EPA should discuss how climate damages affect the growth rate. If damages are assumed to impact investment (which would affect future economic output, and thus the growth rate), this seems to contradict EPA's assumption that damage functions are specified in consumption-equivalent units.[225]

Fifth, given the assumption of a constant savings rate, EPA should explain the basis for the specific savings rate and the methodology used. Similarly, EPA should discuss how the SC-GHG estimates would change if the savings rate varied at the national or regional given historical trends.

- **Geographic scope and reporting** – EPA lists several reasons for selecting a global SC-GHG—including the potential impacts on U.S. citizens living abroad, U.S. overseas military bases and investments, and regional destabilization caused by climate change. However, non-US impacts estimated by the damage functions used by EPA do not correspond to these impact categories. For example, total non-US mortality damages are not a reasonable estimate of the impacts on U.S. citizens living abroad. Therefore, EPA should consider and discuss reasonable alternatives for estimating potential impacts to U.S. interests that occur in other countries. In

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[221] Drupp *et al.* 2018. Discounting Disentangled. American Economic Journal: Economic Policy, 10 (4): 109-34.

[222] For the 1.5 percent consumption discount rate, EPA sets ρ to 0.01 percent and η to 1.02. For the 2 percent consumption discount rate, EPA sets ρ to 0.20 percent and η to 1.24. For the 2.5 percent consumption discount rate, EPA sets ρ to 0.46 percent and η to 1.42. Drupp *et al.*'s survey found that respondents' answers suggest a mean ρ value of 1.1 percent with a standard deviation of 1.47 and a median value of 0.5 percent.

[223] Drupp *et al.* 2018 at 61.

[224] SC-GHG Report at 22.

[225] *See* SC-GHG Report at 53.

addition, while EPA holds that not all spillover costs are properly attributed in regional breakdowns, as discussed further in Section III.c.1. below, the public would still benefit from SC-GHG estimates reported regionally, consistent with Circular A-4. EPA's SC-GHG Report also assumes that U.S. GHG mitigation activities, such as emissions pledges and the use of the global SC-GHG, engender international reciprocity. However, if EPA justifies the use of the global SC-GHG based on these factors, then the Agency should explain why its global emissions projection does not reflect globally coordinated action. Reasonable alternatives that maintain consistency between the geographic scope and the emissions trajectories should be considered and discussed.

- **Incorporation into regulatory cost-benefit analysis** – Given EPA's selection of a 1.5, a 2, and a 2.5 percent near-term discount rate, EPA's proposed SC-GHG discount rates no longer correspond to the typical regulatory consumption discount rate of 3 percent. Additionally, EPA's Ramsey discount rate approach further diverges from the constant discount rate approach used throughout federal cost-benefit analyses. Given that the announced revisions to Circular A-4[226] have not been finalized, API believes that it is inappropriate to incorporate EPA's new SC-GHG estimate in regulatory analysis until Circular A-4 is updated, as it is difficult to understand how EPA's SC-GHG approach for estimating climate benefits could be reasonably combined with other estimated benefits and cost streams discounted at different rates following standard A-4 guidance. For example, were EPA or another agency to use the EPA's SC-GHG estimates to present new benefit estimates in an RIA without updating the cost side of the ledger using the same near-term consumption discount rate used in the SC-GHG Report, the inconsistency between the discount rates used for benefits and costs would bias the cost-benefit analysis and undercut the rationality of the RIA's conclusions.

  EPA discusses the shadow price of capital, the preferred approach by Circular A-4, in Appendix 2 of the SC-GHG Report; however, EPA does not discuss whether or how the Agency plans to use this method in future cost-benefit analyses. To apply this method consistently, both benefits and costs must be adjusted in a similar manner. Whether this overall approach, or the revised discount rates themselves will improve cost-benefit analyses depends on whether and how Circular A-4 is updated to ensure consistency in how costs and benefits are estimated and compared. To avoid exacerbating inconsistencies, EPA should acknowledge this dependency and avoid using revised estimates until OMB guidance is updated, and all reviews are completed.

- **Underestimation of the SC-GHG** - EPA states that "The modeling implemented in this report reflects conservative methodological choices, and, given both these choices and the numerous categories of damages that are not currently quantified and other model limitations, the resulting SC-GHG estimates likely underestimate the marginal damages from GHG pollution."[227] This claim is repeated throughout EPA's SC-GHG Report. However, EPA should provide additional support for this assertion by listing and explaining the range of possible options and how the specific approach ultimately adopted by the Agency represents a conservative methodological choice. Repeating these assertions throughout the SC-GHG Report prior to completion of the IWG's peer review process may hamper objective analysis and may bias the IWG's review.

- **Market rates vs. purchase power parity** – EPA's SC-GHG Report states that "the shift to PPP-based projections in the RFF-SPs . . . represents another advancement in the science underlying the SC-GHG framework presented in this report."[228] However, Bressler and Heal (2022) contend that using "purchasing-power parity is incompatible with a pure Kaldor-Hicks approach."[229] Specifically, Bressler and Heal provide an example in which

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[226] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.

[227] SC-GHG Report at 2.

[228] SC-GHG Report 25.

[229] Bressler R., and Geffrey Heal. 2022. Valuing Excess Deaths Caused by Climate Change. National Bureau of Economic Research

a regulation would generate net costs when analyzed in PPP-adjusted dollars but would generate net benefits when analyzed using market exchange rates. EPA should therefore explain how using PPP-adjusted dollars is compatible with the federal government's overall approach to cost-benefit analysis.

c. The SC-GHG Report Should Fully and Explicitly Discuss the Limited Utility of the SC-GHG Estimates

EPA's SC-GHG Report avers that the SC-GHG estimates allow "analysts to incorporate the net social benefits of reducing emissions of greenhouse gases (GHG), or the net social costs of increasing such emissions, in benefit-cost analysis and, when appropriate, in decision-making and other contexts."[230] API agrees that from its earliest development by the IWG, the SC-GHG "was explicitly designed for agency use pursuant to E.O. 12866."[231] That is why the titles of each of the six TSDs the IWG published prior to the 2021 TSD disclaimed that they were "for Regulatory Impact Analysis under Executive Order 12866."[232]

While API agrees with the SC-GHG Report's statement that SC-GHG estimates are used in benefit-cost analysis, we believe EPA should clarify and describe the "decision-making and other contexts" the Agency believes may appropriately be based on SC-GHG estimates.[233] API agrees with the need to take action on climate change and we agree that agencies generally should weigh costs and benefits when considering such actions, but given the significant uncertainty and recognized malleability of SC-GHG estimates through modest changes to one or a few inputs, we cannot support expanded use of the Agency's or the IWG's SC-GHG estimates beyond their originally intended application in cost-benefit analysis. Indeed, in addition to, and in fact because of, the ease with which they can be "manipulated to reflect preferences, philosophies, assumptions, and so on,"[234] the SC-GHG estimates reflect such a broad range of uncertainty that in some contexts they may not effectively assist agencies' broad weighing of costs and benefits, as envisioned in E.O. 12866.

The SC-CH_4 values in EPA's SC-GHG Report and the IWG's 2021 TSD illustrate how agencies can struggle to use the estimates to determine whether a particular course of action will deliver more benefits than costs or *vice versa*. In the SC-GHG Report, the "nine separate distributions of estimates"[235] for avoided SC-CH_4 damages in 2030 range from $1,100 per metric ton to $3,700 per metric ton.[236] The 2021 TSD's estimates for avoided SC-CH_4 damages in 2030 range even more widely from $940 per metric ton to $5,200 per metric ton.[237] From a policy and regulatory perspective, the difference between $940 and $5,200 per metric ton or even $1,100 and $3,700 per metric ton is immense. A regulatory action that is imminently justifiable to mitigate damages estimated at the higher end of these ranges may be preposterous if proposed to avoid damages estimated at the lower end of these ranges.

"Such a wide range of . . . SC-CO_2 estimates is little more than a mathematical affirmation of the federal court's judgment that 'the value of carbon emissions reductions is certainly not zero.'"[238] "However, for the purpose the .

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[230] SC-GHG Report at 1.

[231] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

[232] *See* 2010 TSD; May 2013 TSD; May 2013 TSD (revised); November 2013 TSD; August 2016a TSD (for CO_2); and August 2016b TSD (for Methane and Nitrous Oxide).

[233] API urged the IWG to provide the same clarification on multiple occasions.

[234] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 366.

[235] SC-GHG Report at 66.

[236] SC-GHG Report at 68.

[237] 2021 TSD at 5.

[238] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

. SC-CO_2 was developed— . . .RIAs[] for US federal regulations—such a wide range of SC-CO_2 is not necessarily a problem."[239]

The Electric Power Research Institute ("EPRI") examined 65 federal rules and 81 subrules between 2008 and 2016 that utilized the IWG's SC-CO_2 estimates in their regulatory analyses.[240] EPRI found that "the inclusion of benefits from policy-induced CO_2 emissions changes does not change the sign of net benefits. In other words, the net benefits are positive with and without consideration of CO_2 reduction benefits."[241]

Thus, while the broad range of uncertainty inherent in the IWG's SC-GHG estimates would appear to preclude their use in most cost-benefit analyses, in practice, the estimates have been used in analyses in which the difference between costs and benefits was larger than the SC-GHG estimates' range of uncertainty. This demonstrates that for those actions with non-climate benefits that are already estimated to exceed costs by a substantial margin, the IWG's SC-GHG estimates' range of uncertainty will not matter.

The extent of uncertainty and speculation that besets the SC-GHG estimates developed by the IWG and EPA alike precludes their reduction to a single value, be it a central value or otherwise. The IWG's SC-GHG estimates "were developed . . . with a methodology to fit the specific purpose of a benefits estimate to be added to a regulatory impact analysis . . ."[242] While EPA's SC-GHG Report adopts a modular approach in lieu of reliance on the IAMs used by the IWG, the reality of the SC-GHG estimation process is "that a high degree of uncertainty is baked in and cannot reasonably be estimated away."[243] At best, this enterprise is capable of producing "a very wide range of potential" SC-GHG estimates.[244]

> In aggregate, the SCC estimates developed by the interagency working group and others represent a strange marriage of conventional economic-financial logic, arbitrary economic-financial logic, massively expansive biophysical phenomena, preference, and uncertainty management utilized to create a digestible input – a dollar amount – for use in the dominant cost-benefit analysis . . . framework.[245]

Moreover, the subjective judgements that are necessary inputs into the SC-GHG estimation process make the product of those modeling exercises malleable. Indeed, SC-GHG estimates "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[246] Thus, "[f]or these assumptions, the tools of science, economics, or statistics are incapable of providing a 'best' or single value."[247]

> [P]roducing a wide range of SC-CO_2 estimates is simply the best we can do using this methodology, and it is the best we will ever be able to do. The . . . Central SC-CO_2 is not an optimal price of CO_2 emissions or a best estimate of the benefits of CO_2 reductions. It is a noncomprehensive estimate

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[239] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[240] Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.

[241] Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.

[242] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[243] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 364-5.

[244] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[245] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 348.

[246] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 369.

[247] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

> of the benefits of GHG reductions using one set of assumptions that is arguably defensible given the theoretical and methodological challenges associated with the approach.[248]

In addition to the methodological limitations precluding the use of the SC-GHG estimates in royalties, subsidies, fees, or applications that require a single value or narrow range of uncertainty, there are legal, statutory, and practical constraints on more expansive use of SC-GHG estimates as well. Indeed, courts have generally only upheld agencies' use of the SC-GHG estimates in the context of cost-benefit analyses.[249]

While some courts have held that agencies must estimate the costs of GHG emissions when assessing impacts of their proposed actions under the National Environmental Policy Act ("NEPA"), the agencies' impact assessments in those cases typically included cost-benefit analyses that are not required by NEPA.[250] In other words, because the agencies there estimated quantified benefits of certain actions, they also had to estimate quantified costs including of GHG emissions. In many other cases, courts have held that agencies have no obligation to use the SC-GHG estimates in analyzing impacts under NEPA.[251] Indeed, many of these courts took favorable views of agency determinations that SC-GHG estimates are ill-suited for NEPA analyses based on uncertainty ranges or otherwise.[252] Courts have generally taken a similar view to the Federal Energy Regulatory Commission's ("FERC's") prior position that the SC-GHG estimates' broad variability range makes them unsuited for public interest determinations[253] under the Natural Gas Act.[254] And in the context of collecting royalties and other financial obligations related to the leasing, production, and sale of minerals from federal and Indian lands, the federal government is affirmatively prohIbited from considering the SC-GHG estimates.[255]

Indeed, regardless of whether the Administration continues to rely on the IWG's estimates or those newly proffered by EPA in the SC-GHG Report, the SC-GHG estimates' broad range of variability and uncertainty render them inappropriate for use in any project-level or site-specific application. In addition, while analyses at these scales might be capable of monetizing some impacts (such as projected climate impacts), partial monetization is not advisable for several reasons. First, it could be interpreted as emphasizing or de-emphasizing the monetized impact, even though there is no basis on which to conclude that a monetized impact is more or less significant than a non-monetized impact. Second, monetized benefits and costs are only meaningful when they are compared to one another in aggregate.

These considerations illustrate the material distinction between formalized cost-benefit analysis in the regulatory context and other types of analysis. Whereas monetization is essential for regulatory analyses, it is potentially misleading outside this application for reasons discussed above. Notably, this material distinction is also embodied

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[248] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

[249] Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 416.

[250] *High Country Conservation Advocates v. U.S. Forest Serv.*, 52 F. Supp. 3d 1174,1181, 1184 (D. Colo. 2014); *See also Mont. Envtl. Info. Ctr. v. U.S. Office of Surface Mining*, 274 F. Supp. 3d 1074, 1096-98 (D. Mont. 2017); *See also Citizens for a Healthy Community v. BLM*, 377 F.Supp. 3d 1223 (D. Col. 2019); *Contrast with WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41; *See also* Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 415.

[251] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020); *See also Citizens for a Healthy Cmty v. U.S. Bureau of Land Mgmt.*, 377 F. Supp. 3d 1223, 1239-40 (D. Colo. 2019); *See also WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 76 (D.D.C. 2019); *See also Wilderness Workshop v. U.S. Bureau of Land Mgmt.*, 342 F. Supp. 3d 1145, 1159 (D. Colo. 2018); *High Country Conservation Advocates v. Forest Service*, 333 F. Supp. 3d 1107 (D. Colo. 2018); *See also W. Org. of Res. Councils v. U.S. Bureau of Mgmt*., No. CV 16-21-GFBMM, 2018 WL 1475470, at *13 (D. Mont. Mar. 26, 2018).

[252] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020).

[253] *See* Natural Gas Act,15 U.S.C. § 717f(a), (c) (2012).

[254] *See, EarthReports, Inc. v. Fed. Energy Reg. Comm'n*, 828 F.3d 949,. 953-54 (D.C. Cir. 2016); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 867 F.3d 1357, 1375 (D.C. Cir. 2017) (remanding to FERC for a discussion of whether it still holds the *EarthReports* position); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 672 Fed. Ap 'x 38 (D.C. Cir. 2016).

[255] *See Wyoming v. Jewell*, No. 2:16-CV-0285-SWS (Oct. 10, 2020); *See also* 86 Fed. Reg. 31,196, 31,206 (June 11, 2021).

in E.O. 12866, which distinguishes between "regulatory actions" and "significant regulatory actions" based in part of the projected scale of impact.[256] For each "significant" proposed action, the issuing agency is required to provide a cost-benefit analysis. Thus, existing regulatory guidance essentially equates significance with the need for cost-benefit analysis, which in turn, implies full monetization of costs and benefits. While (as discussed above), there are inherent limits to the usefulness of SC-GHG estimates in rulemaking, consideration of SC-GHG values is sensible in situations where all costs and benefits are monetized. Consideration of the SC-GHG estimates is not appropriate in instances where only a subset of impacts can be monetized; accordingly, restricting its use to significant regulatory actions ensures consistency with this principle.

d. **The SC-GHG Report Needlessly Limits the Utility of EPA's SC-GHG Estimates by Failing to Present Domestic SC-GHG Estimates Alongside Global Estimates**

In order to conduct a valid and legally-defensible cost-benefit analysis, agencies must ensure that they weigh costs and benefits of the same scale and of the same type. Therefore, consistent with API's repeated requests to the IWG, API recommends that EPA's SC-GHG Report present domestic SC-GHG estimates alongside global estimates. Indeed, we believe that, absent a clear congressional directive otherwise, agency cost-benefit analyses should be constructed to weigh domestic costs against domestic benefits. By doing so, agencies can better ensure that projected domestic impacts alone justify the costs to be imposed on domestic industries. When agencies have failed to do so and weighed domestic costs against global benefits, they have effectively put their thumb on the scale in favor of regulatory action. Such an analysis is not only inconsistent with basic economic principles it overlooks "the more prosaic commonsense notion that Congress generally legislates with domestic concerns in mind."[257]

Given that EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, the CAA provides a particularly relevant example of why the geographic scope of agencies' regulatory analyses should reflect the intended scope under which the regulation is proposed or promulgated.[258] In CAA Section 101(b)(1), Congress expressly stated that the statute's purpose is to "protect and enhance the quality of the *Nation's* air resources so as to promote the public health and welfare and the productive capacity of *its population*."[259] By focusing on "the Nation" and "its population," Congress clearly demonstrated that it enacted the CAA to affect domestic air quality.

This interpretation of the CAA is not new, nor does it fail to reflect the global nature of climate change. Indeed, EPA relied on this interpretation when it issued the highly important Endangerment Finding on which multiple federal climate change regulatory actions have been based.[260]

In addition to the clear inferences that can be drawn from Congress' statements of statutory intent, the text of specific provisions of the statute confirms that Congress intended to limit the reach of the Act to domestic effects, unless it expressly provided otherwise. In only two discrete instances, Congress explicitly addressed the foreign effects of domestic air emissions in the CAA.

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[256] *See* E.O. 12866 at Sec. 3.

[257] *RJR Nabisco, Inc. v. Eur. Cmty.*, 136 S. Ct. 2090, 2100 (2016).

[258] 87 Fed. Reg. at 74,713.

[259] CAA § 101(b)(1) (emphasis added).

[260] *See* Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the CAA, 74 Fed. Reg. 66496, 66514 (Dec. 15, 2009) ("[T]he primary focus of the vulnerability, risk, and impact assessment is the United States").

First, in Title I of the Act, Congress authorized EPA to consider the foreign effects of domestic air emissions within the delineated framework of Section 115. There, Congress defined the process for EPA to evaluate and address reports of domestic air pollution possibly affecting public health or welfare in a foreign country.[261] Critically, this only applies when the Administrator finds there is "reciprocity" such that "the United States essentially [has] the same rights with respect to the prevention or control of air pollution occurring in that country as" Section 115 gives to the foreign country.[262]

Second, in Title VI of the CAA, Congress addressed the global impacts of domestic stratospheric ozone emissions by, among other actions, listing ozone-depleting chemicals of concern, establishing reporting requirements for manufacturers and other entities, and phasing out the production of certain chemicals.[263] Congress expressly enacted Title VI in 1990 in order to implement the Montreal Protocol on Substances that Deplete the Ozone Layer, an international treaty signed by the United States, which addresses stratospheric ozone.[264]

These two discrete provisions (Section 115 and Title VI) represent the full extent of EPA's authority to consider the international benefits of domestic regulation. Critically, these provisions demonstrate that, when Congress chose to allow the Agency to consider foreign impacts of domestic regulation, it said so expressly. These two provisions also reflect the very narrow purpose for which Congress allowed EPA to consider foreign impacts of domestic regulation. Both provisions deal with international agreements under which the United States and one or more foreign nations make reciprocal commitments to impose regulations within their borders that confer benefits outside their borders and/or to the other party.

In these two narrow circumstances, the United States is the beneficiary of EPA's action and also the foreign nation's reciprocal regulatory action. As such, while foreign impacts are considered, their consideration is solely intended to inform regulatory decisions seeking to maximize domestic benefits of reciprocal regulatory actions. The executive branch has ample authority to act for the benefit of foreign nations, but the CAA is generally not one of the statutes that confers that authority. With the exception of these two discrete provisions, the CAA arguably precludes EPA from weighing international benefits against domestic costs.[265]

In addition to the limitations that the CAA places on EPA specifically, OMB guidance applies these same principles government-wide. In support of limiting the use of international benefits for justifying regulation, OMB directs agencies developing regulatory analyses to focus on the "benefits and costs that accrue to citizens and residents of

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[261] CAA § 115(a)-(b).

[262] CAA § 115(c).

[263] EPA, 1990 CAA Amendment Summary: Title VI (Jan. 4, 2017), https://www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary-title-vi.

[264] 42 U.S.C. § 7671m(b) ("This subchapter as added by the CAA Amendments of 1990 shall be construed, interpreted, and applied as a supplement to the terms and conditions of the Montreal Protocol.").

[265] Settled principles of statutory interpretation further confirm that Congress did not intend to authorize EPA to rely on the foreign effects of U.S. emissions in promulgating regulations under the CAA. For one, statutes are construed to give effect to all provisions. *See, e.g., Hibbs v. Winn*, 542 U.S. 88, 101 (2004) ("A statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or superfluous, void or insignificant….") (citations omitted). Section 115 would effectively be a nullity if EPA read the Act to provide the Agency with the authority to consider effects of domestic emissions on foreign countries without following the Section 115 process. Moreover, it is also a well-settled canon that if Congress addressed an issue in one provision, its failure to address that same issue elsewhere confirms its limited intent. *See, e.g., Russello v. United States*, 464 U.S. 16, 23 (1983) ("[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (citations omitted).

the United States"[266] and directs agencies which "choose to evaluate a regulation that is likely to have effects beyond the borders of the United States" to report those impacts "separately."[267] OMB's guidance further states that an agency's cost-benefit analysis "should focus on benefits and costs that accrue to *citizens and residents of the United States*."[268]

Notwithstanding that OMB Circular A-4 mandates agency consideration of domestic costs and benefits while simply allowing for optional consideration of non-U.S. benefits, EPA's SC-GHG Report omits any calculation of domestic benefits. In lieu of this important, and arguably mandatory presentation of domestic benefits, the SC-GHG Report merely offers the EPA's justification for its absence.[269] While these justifications are perhaps sufficient to support the EPA's decision to present global benefits in the SC-GHG Report, none explain the Agency's refusal to also present an estimate of domestic benefits alongside the global value.

For instance, the IWG argues that analyzing the global benefits of U.S. regulatory actions can help generate reciprocal actions from other countries and "allows the U.S. to continue to actively encourage other nations . . . to take significant steps to reduce emissions."[270] Even assuming such effect occurs, the goal of the SC-GHG estimation process should not be the development of tools to aid in international negotiations or which help the U.S. "actively encourage" reciprocal actions on climate change; President Biden required use of the "best available economics and science"[271] to estimate as accurately as possible the societal costs of adding a small increment of GHG into the atmosphere in a given year. To the extent EPA is attempting to assume the IWG's assigned role of developing SC-GHG estimates, the Agency must also assume the obligation to dispassionately and objectively estimate the SC-GHGs using "best available economics and science."[272] And that obligation cannot be construed to encompass an advocacy role. Even if it were reasonable for EPA's interest in advocating for intergovernmental cooperation to shape how it estimates the SC-GHG, the EPA's SC-GHG Report provides no explanation why that advocacy role would be undermined by the presentation of domestic benefits *alongside global benefits*.

EPA also offers that:

> The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to the U.S. population.[273]

Although the U.S. could be adversely impacted by potential climate change damages that could occur in other countries, it does not follow that the EPA must therefore include the potential *damages in those other countries* as part of the SC-GHG estimate. Rather, the Agency should include in the SC-GHG estimates the potential *domestic impact* of those reasonably projected extraterritorial climate damages. As explained by the NASEM:

> Correctly calculating the portion of the SC-CO_2 that directly affects the United States involves more than examining the direct impacts of climate that occur within the country's physical borders . . .

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[266] OMB, Circular A-4, at 15.
[267] OMB, Circular A-4, at 15.
[268] OMB, Circular A-4, at 15 (emphasis added).
[269] *See* SC-GHG Report at 10-15
[270] SC-GHG Report at 14.
[271] E.O. 13990 at Sec. 5(b)(ii)(D).
[272] E.O. 13990 at Sec. 5(b)(ii)(D). Notably, and as previously discussed, E.O. 13990 expressly assigned the SC-GHG estimation development process to the IWG and precluded agencies from developing and using their own values.
[273] SC-GHG Report at 11.

> Climate damages to the United States cannot be accurately characterized without accounting for consequences outside U.S. borders.[274]

In other words, regardless of whether climate change imposes costs on the U.S. directly or indirectly through potential damages in other countries, the costs EPA should be attempting to characterize are those anticipated to be borne by the U.S. and its citizens. Thus, the global nature of climate change is consistent with and supported by the presentation of domestic benefits in the SC-GHG estimates. And the global nature of this issue certainly does not explain why the domestic benefits should not at least be presented alongside projections of global benefits.

EPA's final rationale for declining to present domestic benefits alongside global values is that there are relatively few region- or country-specific SC-GHG estimates or models with sufficient resolution to estimate SC-GHG benefits on a country-specific basis.[275] At the same time, EPA has largely limited its own consideration of damage functions to those that can be specified at the national or sub-national level, suggesting that domestic impacts could be reasonably estimated in two of the three frameworks adopted.[276] Although we agree that there is a high level of uncertainty in the regional or country-specific SC-GHG estimates, we believe it is inconsistent for EPA to use this uncertainty to rationalize its decision to decline to provide any SC-GHG estimates other than global, particularly given EPA's decision to severely restrict consideration of damage functions to precisely those that provide such information. Uncertainty and speculation pervade every aspect of the SC-GHG estimates, and the Agency should explain why such uncertainty provides a valid basis to decline to render estimates in this instance, but presents no barrier in every other respect.

It is also increasingly inaccurate for EPA to cite the overall paucity of literature on regional and country-specific SC-GHG estimates. As noted by the NASEM in 2017:

> Estimation of the net damages per ton of CO_2 emissions to the United States alone, beyond the approximations done by the IWG, is feasible in principle; however, it is limited in practice by the existing SC-IAM methodologies . . .[277]

Indeed, EPA's SC-GHG Report identifies a number of new models and academic efforts that have enhanced our ability to model SC-GHG benefits with greater spatial resolution.[278] While these country-specific estimates remain highly uncertain and divergent, they all broadly agree that the SC-GHG in the U.S. is a small fraction of the SC-GHG Report's estimates of the global SC-GHG.

Although country-specific SC-GHG estimates remain quite imprecise, they are highly relevant because EPA and other agencies should not adopt rules which could impose massive costs on the U.S., but for which the claimed benefits primarily accrue overseas—certainly not without a clear and explicit directive from Congress. EPA's assertion that rule writers and policymakers use only the global SC-GHG estimates in cost-benefit analysis results in

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[274] NASEM 2017 at 52-53.

[275] SC-GHG Report at 77-80.

[276] SC-GHG Report at 39 ("Based on a review of available studies using these approaches, the SC-GHG estimates presented in this report rely on three damage functions. They are: 1. a subnational-scale, sectoral damage function estimation (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (CIL 2022, Carleton et al. 2022, Rode et al. 2021)), 2. a country-scale, sectoral damage function estimation (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert et al. 2022b)), and 3. a meta-analysis-based global damage function estimation (based on Howard and Sterner (2017)).").

[277] NASEM 2017 at 53.

[278] SC-GHG Report at 77-80.

a significant misalignment of costs and benefits, particularly for regulatory actions, like the Proposed NSPS Revisions, that are promulgated pursuant to the CAA.

As such, API's modest recommendation, which we have also previously voiced to the IWG, is not that the federal government abandon the global SC-GHG estimates, but that it simply present domestic SC-GHG estimates alongside global values. This approach would allow risk managers to more readily align the costs with the benefits. Consistent with OMB guidance, the costs of a rule for entities in the U.S. should be presented in comparison with the benefits occurring in the U.S.

IV. CONCLUSION

API appreciates the opportunity to provide these comments on EPA's SC-GHG Report. We hope this comment opportunity is the first step toward a more open and transparent process for developing SC-GHG estimates and the judgment and assumptions used to develop and portray those estimates.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, EPA's unilateral development of SC-GHG estimates raises a number of questions and concerns the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the IWG.

President Biden's issuance of E.O. 13990 on his first day in office reflects the importance of the SC-GHG estimates to our nation's climate policies and regulations. Given the importance of these estimates, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each module had been updated and the SC-GHG Report had been fully drafted. Moreover, given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is wholly insufficient for soliciting detailed feedback from informed stakeholders.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. In fact, EPA has not even clearly explained why it developed the SC-GHG Report or how it intends the SC-GHG Report's estimates to be used. Nonetheless, where possible, API has tried to provide EPA relevant analysis and constructive recommendations for improving the reliability and utility of the SC-GHG Report and the estimates therein. We did so, not only with the intent of improving the SC-GHG estimates and the process through which they are developed, but with the hope that by providing credible analysis and constructive feedback, EPA would more fully recognize the benefit of engaging stakeholders in a more open, data-driven, and collaborative process.

API recognizes the need to confront the challenges of climate change. However, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. Indeed, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.

Thank you again for your consideration of these comments. If you have any questions or would like to discuss these comments, please feel free to contact Andrew Baxter at (202) 268-2800 or baxtera@api.org.

Sincerely,

Andrew Baxter
Economic Advisor, Policy Analysis
American Petroleum Institute

ANNEX D: API Barnett and Bakken Mantis Field Studies

PROVIDENCE PHOTONICS

American Petroleum Institute Mantis™ Field Study

Final Report | Revision 1.0

September 2023

PROJECT 0040-001

API BARNETT

PREPARED BY
Providence Photonics, LLC | 1201 Main Street, Baton Rouge, LA 70802

Table of Contents

Introduction

Providence Photonics, LLC (Providence) has developed a method to remotely measure the performance of an industrial flare using Video Imaging Spectral Radiometry (VISR). The VISR method provides five flare performance metrics: combustion efficiency (CE), smoke index (SI), flame stability (FS), flame footprint (FF), and fractional heat release (FH). The VISR method is incorporated into Providence's Mantis™ flare monitoring product (Mantis).

Providence used the Mantis device to conduct a flare measurement in the Barnett regions for American Petroleum Institute (API) in September of 2023. The measurements were performed from September 11th, 2023 to September 16th, 2023. This report summarizes the Mantis data and associated findings from the study.

Background

The VISR method utilizes a multi-spectral mid-wave infrared imager to measure the radiance from both hydrocarbons being combusted and carbon dioxide (CO_2) as complete combustion product, and use that information to determine the combustion efficiency. The method was designed to be a continuous and autonomous remote flare monitor, but in this study it was deployed as a mobile technology for a short-term measurement. ***Figure 1*** below shows the Mantis device deployed at one of the sites during the Barnett study.

Figure 1: Mantis deployed during API field survey in Barnett region.

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%. CE should not be confused with Destruction and Removal Efficiency (DRE). The difference between these two metrics is discussed in **Appendix C**. While CE is directly measured by the VISR method, DRE is derived using correlations established through extractive sampling as discussed in **Appendix C**.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 3 generally indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the Mantis flare monitor. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the Mantis flare monitor in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope, the outer layer of the flame where the combustion process has ceased. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this study, any measurements with less than 30 pixels were removed from the summary tables and **Appendix A**.

The second important DQI is the Smoke Index level. As the smoke index increases above 3.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Testing has shown that SI values above 3.0 may cause a small negative bias on the CE measurement by VISR (< 1%) and SI values above 5 may cause a significant negative bias to CE measured by VISR, as confirmed by testing with an extractive sampling method as a control (note that in the extractive sampling method, carbon soot is not included in the CE calculation). Any data points with a smoke index above 5 were removed from the summary tables and **Appendix A** as they are considered outside of method limits.

Observations

The following sections describe field observations and comparisons derived from the dataset.

Aggregate results

The flare measurements included sites from three companies ([redacted] In total, there were 39 individual flares measured. The distribution of the DRE measurements is represented in ***Figure 2*** below.

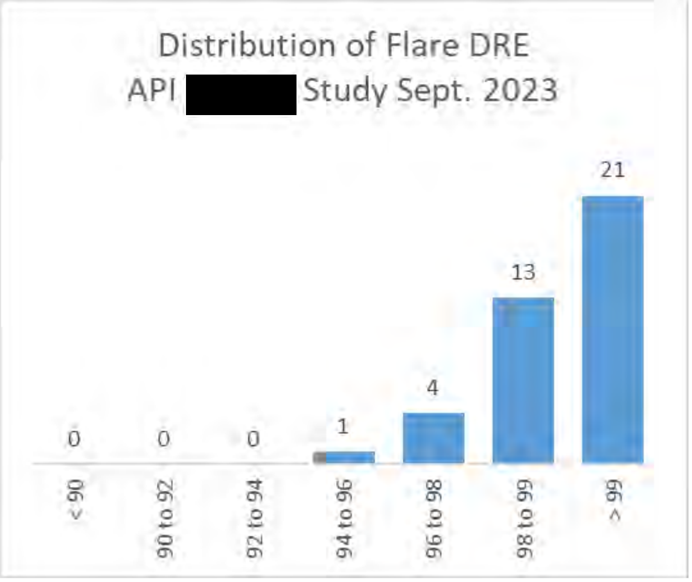


Figure 2: HP and LP flare tips on Green Canyon 254.

Summary

Providence conducted flare measurements on 39 flares in the Barnett region from September 11th, 2023 to September 16th, 2023. The measurement summaries are provided in ***Table 1*** and ***Appendix A*** with the distribution of the measurements provided in ***Figure 2***. Overall efficiencies across the study were high, with 87% of the flares demonstrating a DRE above 98%.

References

1. Yousheng Zeng, Jon Morris & Mark Dombrowski (2015) Validation of a new method for measuring and continuously monitoring the efficiency of industrial flares, Journal of the Air & Waste Management Association, 66:1, 76-86, DOI: 10.1080/10962247.2015.1114045

2. Yousheng Zeng, Jon Morris. (2019, April 2nd). *Precision and Accuracy of the VISR Method for Flare Monitoring*. Air Quality Measurement Methods and Technology, Durham, North Carolina, United States.

Appendix A: Results

Date/Time				Description		Conditions				Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (Local)	End Time (Local)	Company	Location	Distance (m)	Temp (°C)	RH (%)	WS (mph)	CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	9/11 -9/16	7:57 AM	8:13 AM			54	26	52	2-4	98.88	99.51	97.84	99.45	0.27	0.34	0.01	1.24	0.23	7.4	1.4	18.4	4.1	0.08	0.00	0.25	0.06	91.6	0.1	100.0	8.1
2		9:56 AM	10:12 AM			76	29	42	2-4	99.20	99.53	90.82	100.00	1.38	2.49	1.09	6.21	0.69	56.9	31.4	80.2	10.5	3.19	1.24	5.15	0.81	93.1	75.9	100.0	4.0
3		10:56 AM	11:11 AM			61	31	40	0-2	99.27	99.82	98.16	99.87	0.24	0.22	0.02	0.57	0.14	13.8	0.2	39.9	10.3	0.26	0.00	1.11	0.28	88.4	0.1	100.0	14.2
4		12:29 PM	12:45 PM			69	34	33	2-4	98.98	99.58	97.11	99.83	0.44	0.63	0.20	1.24	0.13	12.9	9.3	16.5	1.4	0.28	0.09	0.35	0.02	94.1	75.8	100.0	3.2
5		1:47 PM	2:04 PM			109	35	29	2-4	98.98	99.58	97.71	99.99	0.37	0.90	0.33	1.53	0.22	18.0	11.3	38.7	2.3	0.42	0.32	0.52	0.03	95.7	59.1	100.0	2.7
6		2:41 PM	2:56 PM			405	36	27	4-6	96.96	97.86	88.75	100.00	1.36	0.75	0.07	4.14	0.61	180.1	62.4	681.0	49.0	1.29	0.12	4.99	0.76	80.8	0.1	100.0	11.7
7		8:15 AM	8:31 AM			97	18	77	2-4	99.40	99.79	94.00	100.00	0.65	1.50	0.69	2.35	0.22	147.9	87.4	182.4	17.2	3.91	1.19	5.24	0.78	95.5	49.4	100.0	2.8
8		9:30 AM	9:45 AM			136	19	77	2-4	98.40	99.09	96.49	100.00	0.74	0.98	0.05	1.58	0.19	101.7	18.2	149.0	19.3	1.85	0.07	2.63	0.36	95.1	74.3	100.0	2.7
9		11:18 AM	11:33 AM		I	116	20	79	2-4	98.61	99.23	96.54	100.00	0.80	1.22	0.78	1.97	0.20	95.7	76.2	125.2	6.7	2.50	1.82	3.08	0.26	95.4	82.9	100.0	2.1
10		12:26 PM	12:42 PM			124	19	82	2-4	98.34	99.05	95.76	99.91	0.58	0.69	0.21	1.28	0.21	28.8	13.6	67.4	7.2	0.45	0.12	0.82	0.16	96.0	70.6	100.0	2.1
11		1:14 PM	1:30 PM			90	20	78	2-4	98.67	99.31	96.83	100.00	0.63	0.80	0.05	1.53	0.27	31.3	3.1	53.3	9.3	0.65	0.01	1.37	0.29	92.4	35.1	100.0	6.5
12		3:11 PM	3:28 PM			116	20	80	2-4	99.99	99.99	98.63	100.00	0.27	4.30	1.28	9.56	1.35	76.5	33.6	133.8	18.4	2.41	0.50	8.43	1.20	90.2	47.7	100.0	5.0
13		9:09 AM	9:17 AM			17	20	82	0-2	97.88	98.66	92.09	99.29	0.73	0.48	0.15	1.01	0.15	0.9	0.3	1.7	0.3	0.02	0.00	0.04	0.01	90.8	0.1	100.0	8.5
14		10:03 AM	10:18 AM			21	20	82	0-2	98.07	98.82	93.01	99.56	0.97	0.49	0.11	1.23	0.16	0.5	0.1	1.9	0.5	0.01	0.00	0.02	0.01	95.0	65.4	100.0	2.9
15		12:34 PM	12:50 PM			38	22	92	0-2	98.57	99.23	93.14	100.00	0.66	0.51	0.07	1.66	0.22	3.0	0.6	8.1	1.1	0.07	0.00	0.16	0.03	84.3	0.1	100.0	12.4
16		1:38 PM	1:40 PM			37	26	68	2-4	93.91	95.28	85.94	99.79	3.15	0.07	0.04	0.28	0.04	0.3	0.0	1.0	0.2	0.00	0.00	0.02	0.00	50.1	0.1	100.0	32.1
17		2:09 PM	2:24 PM			41	28	45	0-2	97.37	98.23	95.35	98.89	0.46	0.23	0.15	0.78	0.06	0.7	0.3	1.4	0.2	0.01	0.01	0.03	0.00	93.1	75.1	100.0	4.1
18		4:43 PM	4:58 PM			23	31	51	0-2	98.23	98.95	95.91	99.75	0.63	0.21	0.09	0.51	0.06	0.9	0.2	1.7	0.3	0.02	0.01	0.04	0.01	96.2	39.5	100.0	3.1
19		10:39 AM	10:53 AM			94	31	29	0-2	98.11	98.80	92.86	100.00	1.17	0.93	0.43	1.74	0.28	11.7	8.9	32.9	1.5	0.25	0.18	0.35	0.03	95.4	44.2	100.0	3.3
20		12:53 PM	1:08 PM			32	33	36	0-2	95.10	96.29	84.81	99.75	4.41	0.06	0.03	0.12	0.01	0.6	0.0	1.0	0.2	0.01	0.00	0.01	0.00	91.7	0.1	100.0	8.4
21		1:21 PM	1:36 PM			46	32	36	0-2	98.89	99.49	96.33	100.00	0.49	0.95	0.20	2.51	0.31	3.6	0.5	8.4	0.7	0.07	0.00	0.14	0.02	86.5	40.7	100.0	8.7
22		1:58 PM	2:13 PM			44	34	30	0-2	99.31	99.74	90.77	99.99	0.88	0.02	0.01	0.05	0.01	0.9	0.1	1.3	0.2	0.00	0.00	0.01	0.00	85.5	32.7	100.0	8.4
23		2:52 PM	3:07 PM			42	35	27	2-4	98.43	99.11	85.65	99.83	1.80	0.05	0.02	0.66	0.04	0.4	0.0	1.0	0.2	0.00	0.00	0.01	0.00	78.0	0.1	100.0	21.2
24		8:25 AM	8:41 AM			24	21	84	0-2	97.28	98.15	93.97	98.72	0.60	0.68	0.49	0.90	0.08	1.6	0.7	2.0	0.2	0.03	0.02	0.04	0.00	95.1	83.4	100.0	2.5
25		9:27 AM	9:43 AM			10	27	63	2-4	98.21	98.94	96.60	99.98	0.49	0.73	0.23	1.28	0.21	0.3	0.1	1.2	0.2	0.01	0.00	0.05	0.01	92.4	60.2	100.0	4.5
26		10:09 AM	10:40 AM			35	24	71	2-4	98.33	99.04	96.13	99.58	0.57	0.55	0.11	1.07	0.17	1.3	0.0	2.2	0.4	0.01	0.00	0.03	0.01	67.0	0.1	100.0	21.9
27		12:22 PM	12:36 PM			43	29	60	0-2	98.22	98.89	85.50	100.00	1.82	1.47	0.59	4.11	0.57	16.6	7.8	23.1	2.7	0.66	0.21	1.07	0.19	90.7	19.4	100.0	5.5
28		1:05 PM	1:21 PM			52	34	40	0-2	98.65	99.31	96.87	99.66	0.38	0.26	0.02	0.90	0.15	14.3	0.3	32.7	8.2	0.27	0.00	0.91	0.20	88.8	0.1	100.0	13.0
29		2:15 PM	2:30 PM			69	33	49	2-4	97.81	98.60	93.79	100.00	1.27	2.25	0.86	7.96	0.91	39.9	22.2	64.7	6.7	1.60	0.62	3.59	0.45	89.9	53.6	100.0	5.7
30		3:24 PM	3:41 PM			30	30	49	2-4	98.71	99.35	96.51	100.00	0.50	0.65	0.13	1.34	0.19	2.8	0.5	4.3	0.8	0.04	0.00	0.08	0.02	76.6	0.1	100.0	14.3
31		8:45 AM	9:00 AM			27	21	68	0-2	98.03	98.79	89.51	99.64	1.12	0.21	0.12	0.44	0.07	2.8	1.1	4.2	0.6	0.05	0.03	0.08	0.01	97.2	86.5	100.0	1.9
32		9:05 AM	9:40 AM			22	21	68	0-2	95.80	96.89	84.78	99.13	2.92	0.07	0.05	0.11	0.01	1.6	1.2	2.3	0.2	0.02	0.01	0.03	0.00	97.0	88.6	100.0	1.3
33		9:50 AM	10:24 AM			19	22	65	0-2	97.77	98.57	89.12	99.98	2.00	0.50	0.06	1.18	0.27	2.0	1.1	3.0	0.5	0.03	0.01	0.06	0.01	95.7	72.1	100.0	2.1
34		10:51 AM	11:06 AM			25	22	65	2-4	98.36	99.07	97.46	99.29	0.30	0.19	0.09	0.48	0.06	2.0	0.9	2.7	0.4	0.03	0.02	0.05	0.01	95.3	82.9	100.0	2.4
35		11:10 AM	11:25 AM			25	22	65	2-4	98.47	99.16	94.52	99.49	0.70	0.25	0.05	0.79	0.15	0.2	0.1	0.7	0.1	0.00	0.00	0.00	0.00	75.2	31.1	100.0	11.1
36		11:52 AM	12:07 PM			45	24	61	0-2	98.46	99.15	92.84	99.64	0.62	0.10	0.03	0.49	0.06	3.2	0.4	6.4	1.3	0.03	0.00	0.07	0.02	85.0	0.1	100.0	15.8
37		12:22 PM	12:37 PM			15	33	40	0-2	98.16	98.89	96.34	99.73	0.69	1.63	0.69	4.72	0.54	0.5	0.1	0.8	0.2	0.01	0.00	0.02	0.00	89.0	4.6	100.0	8.3
38		1:10 PM	1:27 PM			29	33	41	0-2	98.24	98.96	95.03	99.99	0.54	0.45	0.11	1.36	0.22	2.1	1.0	3.1	0.3	0.03	0.01	0.05	0.01	88.4	44.9	100.0	6.1
39		1:29 PM	1:43 PM		L	34	33	41	0-2	96.24	97.27	89.45	99.84	1.29	0.91	0.07	1.65	0.28	0.3	0.0	1.0	0.2	0.00	0.00	0.01	0.00	51.5	0.1	100.0	29.2

Table 2: Complete Mantis Results.

Appendix B: Validation of the VISR method

Precision and Accuracy of the VISR Method for Flare Monitoring

Extended Abstract: ME92
Presented at the conference:
Air Quality Measurement Methods and Technology
April 2-4, 2019
Durham, NC

Jon Morris, Yousheng Zeng, and Srikanth Mutyala
Providence Photonics, Baton Rouge, Louisiana

Introduction

Industrial flares represent a large category of air emission sources for Volatile Organic Compounds (VOC), air toxics, and greenhouse gases (GHG)[1-4]. Depending on their combustion efficiency (CE), the emissions of these air pollutants can be significantly different. Despite the large contribution of flares to air emission inventories, flares are the only source category for which no EPA test or monitoring methods can be applied to directly measure their efficiency or emission rates. As a result, flare emissions in air emission inventories may carry significant uncertainties.

A method based on Video Imaging Spectral Radiometry (VISR) has been developed for testing or continuously monitoring combustion efficiency (CE) of industrial flares[5]. To validate the VISR method, tests were conducted at flare test facilities of Zeeco, Inc. (Zeeco) and John Zink Hamworthy Combustion (John Zink), both located in Tulsa, Oklahoma, in September and October 2016, respectively. The test at Zeeco included both an air assisted flare and a steam assisted flare. Twenty-eight flare conditions were tested, 14 for the air flare and 14 for the steam flare. This test is referred to as the "Zeeco Test" in this paper.

The test at John Zink was part of a program sponsored and organized by the Petroleum Environmental Research Forum (PERF), an industry consortium. PERF project 2014-10 Direct Monitoring of Flare Combustion Efficiency was created and funded by participating PERF companies to provide a test platform for various developers/vendors of flare remote sensing technologies (Invitees) to participate in a blind test to evaluate the effectiveness of each technology. The blind test was administered by John Zink. Testing began on October 17th, 2016 and continued for 10 days, concluding on October 27th, 2016. The flare tip used was the John Zink model EEF-QSC-36, which was the same flare tip used during the 2010 TCEQ Flare Study[4]. A test protocol was developed which identified a series of test conditions to evaluate various factors that could affect flare CE measurement. Only limited logistical and environmental factors were shared with the Invitees (i.e., distance from the flare, view angle with respect to flame orientation due to wind, sun in/out of the field of view, daytime/nighttime testing). Information regarding flare operations such as the type of fuel gas used, firing rates, steam rates or any other flare operating parameters was concealed from Invitees. A total of 45 test points was evaluated over the 10 days of testing. Extractive sampling was performed on each test point as the control method for flare CE measurement. The results of the extractive sampling were not provided to Invitees until Invitees submitted their won results based on their respective measurement technology. This test is referred to as the "PERF Test" in this paper.

In this paper, the precision and accuracy of the VISR method are evaluated based on the test campaigns described above.

Methods and experimental setup

The VISR flare monitor is a remote monitoring device that can be positioned at any distance as long as the flare to be monitored is in the line of sight and there are a sufficient number of pixels of the flare flame image in the VISR monitor. The distances from flare to the VISR monitor in the experiments reported here were in the range of 174 feet to 650 feet. To evaluate the performance of the VISR method, an extractive sampling system was used as a reference method. A sample extraction apparatus was suspended by a crane over the flare plume to extract combustion product gases. The sample was transported through a heated sampling line to a sample manifold in a testing trailer. The sample manifold was connected to analyzers for oxygen (O_2), carbon dioxide (CO_2), carbon monoxide (CO), and hydrocarbon (HC). The methods for measuring O_2, CO_2, CO, and HC were EPA Method 3A, 3A, 10, and 25A, respectively. The level of O_2 was used to confirm that the sampling probe was in the flare plume. The concentrations of CO_2, CO, and HC were used to calculate flare CE per method used in the 2010 TCEQ flare study[3].

These test campaigns covered a wide range of process conditions: two steam flares and one air flare; multiple vent gas compositions (natural gas, propane, propylene, hydrogen, in pure form or mixed with nitrogen; vent gas flow range from 10 lb/hr to 10,000 lb/hr; various steam and air assist levels resulting in combustion zone net heating value (NHVcz) in a range of 120 to 1,250 Btu/scf for the steam flares and net heating value dilution parameter (NHVdil) in a range of 6.7 to 244 Btu/ft^2 for the air flare.

The test campaigns also covered a wide range of environmental conditions: distance ranging from 174 ft. to 650 ft.; different wind speed and direction (crosswind, wind oriented towards VISR device, and wind oriented away from VISR device); daytime vs. nighttime; various sky conditions (blue sky, cloudy, moving clouds); the Sun in or out of field of view; rain, and fog.

Results and Discussions

Precision

Precision is a measure of how the results of multiple measurements by the same method scatter while the target of the measurement holds steady. This is difficult to assess for flare measurements because even when the flare operating conditions are held steady (as they were in each test point of the PERF Test), the flare CE may change due to changes in environmental conditions. Analyte spiking or quadruplet sampling described in EPA Method 301 would help to isolate the measurement method precision from the fluctuation of the target itself[6]. However, these methods are not feasible for flare measurement. Nevertheless, the measurement precision can still be evaluated using the data from the PERF test. For each PERF test condition, 4 segments of measurement were made by the extractive method and 3 segments of measurement were made by VISR while the flare operating conditions were held constant (although flare CE did fluctuate due to changes in environmental conditions). The standard deviation (SD) and relative standard deviation (RSD) can be calculated based on these replicate measurements. **Table 1** is a summary of the SD and RSD for both the VISR method and the extractive method used in the PERF Test. As shown in **Table 1**, the RSD for the VISR method is in a range of 0.07% to 1.98% with an average of 0.62%. The variation of the VISR method appears to be slightly better than the extractive method from the perspective of both the average and the range of the RSD values, suggesting that the precision of VISR is at least as good as the extractive method. Note that in both cases, the variation due to changing environmental conditions is included in the RSD as there is no practical method to separate it. Despite the inclusion of environmental changes, the RSD is more than an order of magnitude smaller than 20% as required in EPA Method 301 (Section 9.0)[6]. If a more stringent criteria is used in which the 20% limit on RSD is applied to the most relevant range of 90-100 % CE measurement (i.e., in the span of 10 % CE measurement), the criteria would be SD < 2 % CE (20% of 10% = 2 % CE). As shown in **Table 1**, the highest SD is 1.84 measured as % CE, which is lower than the SD of 2 % CE measurement and therefore satisfies the more stringent criteria.

Table 1. Relative Standard Deviation (RSD) of VISR and extractive method per PERF Test

Method	CE Avg.	CE Range	SD Avg.	SD Range	RSD Avg.	RSD Range
VISR	96.47	80.61-99.91	0.59	0.07-1.84	0.62%	0.07-1.98%
Extractive	96.41	83.50-100.00	0.83	0.00-2.61	0.88%	0.00-2.72%

The Zeeco Test did not include multiple replicated measurements under each test condition. Therefore, a precision analysis is not performed on that data.

Accuracy

The accuracy of the VISR method is evaluated based on the Zeeco Test and PERF Test. In these two tests, the flare CE was measured by both the VISR method and the extractive method. The extractive method was used as the control (reference) method. Strictly speaking, what can be assessed is the agreement between the two methods, not the accuracy of either method because the true flare CE is unknown. The agreement between the two methods can be evaluated using a statistical method. One such method is to use t-test on the differences between the paired CE measurements by VISR and extractive methods. This method is the same as the method used in EPA Method 301 to determine if there is a difference caused by different sample storage time[6] (it should be noted that the methods for bias described in Method 301 are not directly applicable because they are specifically designed for analyte/isotopic spiking or quadruplet sampling systems, which are not feasible for flare measurement). The value of the t-statistic is calculated using the following equation.

$$t = \frac{|d_m|}{\frac{SD_d}{\sqrt{n}}}$$

Where d_m and SD_d are the mean and the standard deviation of the difference of the paired samples (VISR and extractive sample), and n is the total number of samples. The resulted t-statistic value is compared to the critical value of the t-statistic with a 95 percent confidence level and n-1 degree of freedom. If the resulted t-statistic value is less than the critical value, the difference between the VISR method and the extractive method is not statistically significant, i.e., the two methods are statistically the same. The results of the t-statistical analysis for both Zeeco and PERF tests are summarized in **Table 2**. The number of samples (tests) in **Table 2** is less than the number of tests actually conducted because some tests were designed for other purposes (e.g., smoke test) and they are not included in the evaluation of the agreement between VISR and extractive methods.

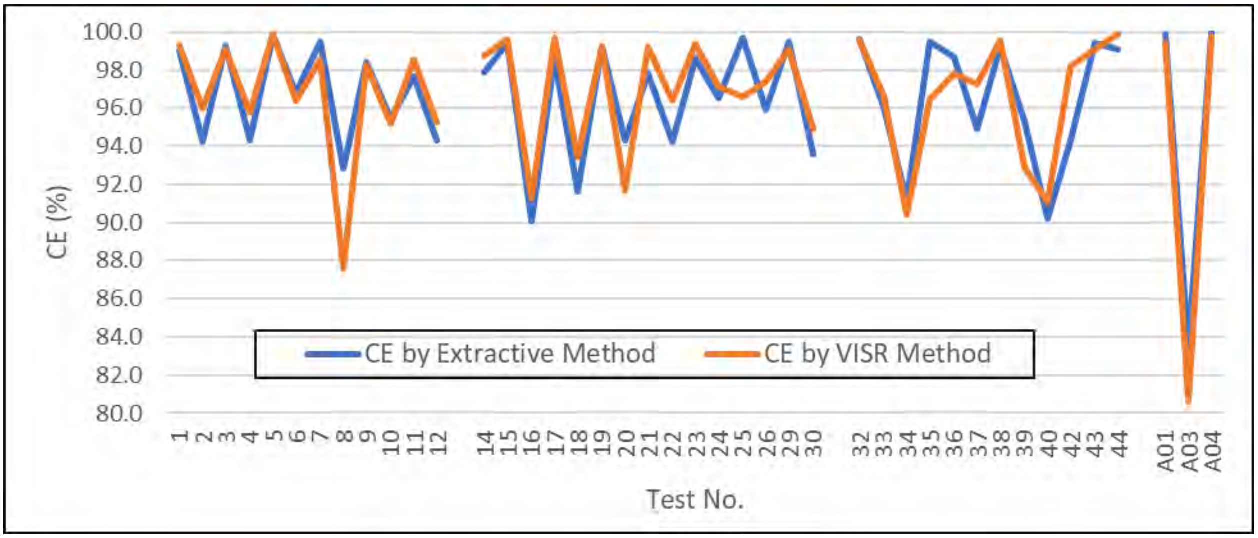
Table 2. t-Test to determine if the VISR method is different from the extractive method

	Zeeco Test (Steam Flare)	**Zeeco Test (Air Flare)**	**PERF Test**
No. of Samples, n	11	9	42
Mean Difference, d_m (% CE)	0.30	-0.21	0.07

Standard Deviation, SD_d (% CE)	1.32	0.65	1.69
t-Statistic Value	0.756	0.967	0.254
Degree of Freedom	10	8	41
t_95 Critical Value	2.228	2.306	2.020
Statistically Different?	No	No	No

As demonstrated in **Table 2**, statistically there is no difference between the flare CE measured by the VISR method and by the extractive method. The agreement between the two measurement methods can also be illustrated in **Figure 1** using the results from the PERF Test.

Figure 1. Flare CE measured by VISR method and extractive method – PERF Test results



Conclusion

Industrial flares can now be measured or continuously monitored by the VISR method for their performance, i.e., combustion efficiency (CE). The VISR method is a remote sensing method and can be deployed easily and practically. The VISR method transforms flare testing/monitoring from most difficult task (impossible in many cases) to a task that is easier than most conventional air emission testing methods. With the significant potential benefits that the VISR method can bring, it is important to characterize and understand the precision and accuracy of this method.

Through a large number of tests under various process and environmental conditions, a high precision and accuracy have been demonstrated for the VISR method. The relative standard deviation (RSD) is in the range of 0.07-1.98% with an average RSD of 0.62% for flare CE in the range from 80 to 100%. The average RSD of 0.62% is more than an order of magnitude smaller than the minimum precision target of 20% RSD set in EPA Method 301. The highest SD is only 1.84 measured as % CE.

The flare CE measured by the VISR method is in excellent agreement with the flare CE measured by the extractive method. The mean difference between the two methods is in the range of -0.21 to 0.30 measured in % CE. The t-statistic value in each of the three test groups are well below its corresponding t-test critical value, passing the t-test with a substantial margin. Keep in mind that the extractive method is suitable only in research. It is virtually impossible to deploy the extractive method to elevated flares at industrial production facilities. Having a method that can be easily deployed to industrial sites and produce highly time-resolved and accurate flare measurement results is a significant advancement.

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6. U.S. EPA, *Code of Federal Regulations*, Title 40, Part 63, Appendix A, Method 301, 2018.

Appendix C: Combustion Efficiency Versus Destruction Efficiency

With respect to emissions calculations or GHG reporting, it is important to consider the difference between combustion efficiency (CE) and destruction efficiency (DE). The VISR method measures CE, which is a measure of the efficiency of the flame to convert hydrocarbons into carbon dioxide and water. If the combustion efficiency is 100%, then all of the hydrocarbons have been oxidized all the way to carbon dioxide, leaving no hydrocarbons in the post combustion plume. CE will be reduced as the percentage of hydrocarbon in the post combustion plume increases. Destruction efficiency is a measure of the percentage of a compound that is destroyed (IE converted into another form), but not necessarily oxidized to the ultimate combustion product of carbon dioxide and water. In this case, it represents the percentage of hydrocarbons destroyed. The hydrocarbons could be converted to carbon dioxide, carbon monoxide, soot or another compound. As a result, DE is typically higher than CE. For emission inventory purposes, flares are generally deemed to have a DE of 98%, meaning 98% of the hydrocarbons sent to the flare are converted into another form. There is no quantitative method to convert the VISR CE data to DE, however we do have some points of reference. The US EPA Refinery Sector Rule (40 CFR 63.670 (r) equates a CE of 96.5% to a DE of 98%. The rule references the John Zink combustion handbook (Baukal, 2001).

In addition, there have been two major studies which have measured both CE and DE with extractive sampling: the 2010 TCEQ Study and the 2016 PERF Study. Both of these studies were conducted at John Zink's research facility in Tulsa, Oklahoma. Taken collectively, these studies provide 71 individual measurements of CE and DE. *Figure 8* below shows the relationship between CE and DE from these two studies.

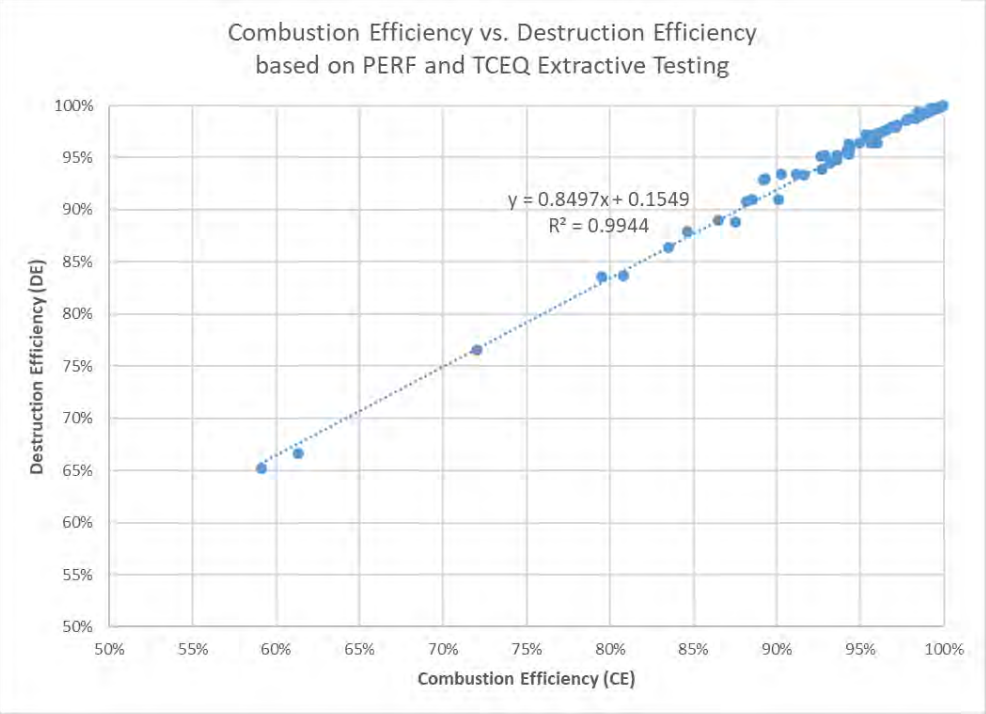

Figure 17. CE vs DE from extractive sampling during PERF and VISR studies.

As demonstrated by the chart, the relationship between DE and CE is quite linear. The fit equation to this data has an R^2 of 0.99. Equation 2 below can be used to convert CE to DE using this correlation:

$$DE\ (\%) = CE\ (\%) * 0.8497 + 0.1549$$

Equation 2

It should be noted that when SI is high and CE appears to be low, the destruction efficiency (DE) may still be high as the hydrocarbons are combusted into soot instead of oxidizing to the ultimate combustion products of water and CO_2. The CE-DE relationship shown in *Figure 8* is established under no smoke conditions. There has not been sufficient study on a similar CE-DE relationship when there is significant smoke in the flare. This equation will be valid for CE within a range of 60% to 99.4%. Above 99.4%, the DE will be capped at 100%. Below 60%, there is no extractive data available to extend the correlation.

[redacted]

VISR Field Study

Final Report | Revision 1.0

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[redacted]

NORTH DAKOTA

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Table of Contents

Introduction

Providence Photonics, LLC (Providence) has developed a method to remotely measure the performance of an industrial flare using Video Imaging Spectral Radiometry (VISR). The VISR method provides five flare performance metrics: combustion efficiency (CE), smoke index (SI), flame stability (FS), flame footprint (FF), and fractional heat release (FH).

Providence conducted a field campaign using VISR at various [redacted] facilities in North Dakota from April 4th, 2022 to April 8th, 2022. A total of 92 individual flare measurements were performed. In addition to the VISR measurements, an mp4 video was captured for each flare using a FLIR GF320 optical gas imaging camera. This report summarizes the data and findings from the campaign.

Background

The VISR method utilizes a multi-spectral midwave infrared imager to measure relative concentrations of combustion gases. The method was designed to be a continuous and autonomous remote flare monitor, but in this study it was deployed as a mobile technology for a short-term measurement. ***Figure 1*** below shows the VISR device deployed at a [redacted] facility in North Dakota. The VISR device and related equipment was powered from the 12V battery system of the vehicle.

Figure 1: VISR device deployed at a [redacted] facility in North Dakota.

Results

The results from VISR measurements are tabulated in **Appendix A** and a summary is provided in *Table 1 below.*

Table 1: Summary VISR Results.

ID	Site Description	Flare Description	Distance (m)	Temp (°C)	RH (%)	Avg Wind Speed (mph)	FLIR Video	CE Avg (%)	DRE Avg (%)	SI Avg	FF Avg (m2)	FH Avg (MMBT	FS Avg (%)
1	[redacted]	High Pressure	46	3	72	4 to 6	MOV_2332.mp4	98.12	98.86	1.0	0.4	0.004	89.1
2		Low Pressure	54	3	72	4 to 6	MOV_2334.mp4	99.68	99.94	0.3	0.3	0.004	96.8
3		High Pressure	38	9	53	4 to 6	MOV_2337.mp4	99.50	99.93	0.8	1.4	0.021	95.5
4		Low Pressure	46	9	53	4 to 6	MOV_2338.mp4	99.05	99.63	0.7	1.4	0.025	96.6
5		High Pressure	44	8	59	8 to 10	MOV_2339.mp4	99.76	99.95	0.2	3.4	0.051	96.2
6		Low Pressure	61	8	59	8 to 10	MOV_2340.mp4	99.35	99.83	0.6	0.5	0.004	93.7
7		High Pressure	45	10	53	4 to 6	MOV_2341.mp4	99.54	99.92	0.5	0.6	0.007	81.8
8		High Pressure	42	11	50	6 to 8	MOV_2342.mp4	99.03	99.61	0.4	1.8	0.028	93.6
9		Low Pressure	53	11	50	6 to 8	MOV_2344.mp4	99.36	99.86	0.4	0.9	0.011	91.0
10		Low Pressure	44	14	39	12 to 14	MOV_2348.mp4	98.90	99.52	0.6	0.7	0.010	93.4
11		HP/LP Assisted	49	14	38	14 to 16	MOV_2351.mp4	97.66	98.47	0.2	5.5	0.088	97.4
12		High Pressure South	49	14	38	14 to 16	MOV_2354.mp4	98.59	99.23	1.5	3.4	0.092	92.5
13		Low Pressure South	52	14	38	14 to 16	MOV_2356.mp4	99.46	99.89	0.7	0.1	0.001	92.1
14		High Pressure North	38	14	38	14 to 16	MOV_2358.mp4	98.88	99.50	0.1	0.3	0.003	92.6
15		Low Pressure North	32	14	38	14 to 16	MOV_2359.mp4	99.49	99.85	0.3	0.1	0.001	89.4
16		High Pressure	37	18	32	10 to 12	MOV_2362.mp4	98.04	98.79	0.4	1.2	0.020	89.9
17		Low Pressure	45	18	32	10 to 12	MOV_2363.mp4	98.59	99.26	0.7	0.1	0.001	94.5
18		High Pressure	34	19	32	12 to 14	MOV_2365.mp4	98.90	99.51	0.6	0.2	0.002	95.2
19		Low Pressure	38	19	32	12 to 14	MOV_2366.mp4	98.46	99.15	0.1	0.5	0.007	93.3
20		High Pressure	37	19	30	8 to 10	MOV_2367.mp4	98.68	99.34	0.2	3.2	0.056	96.7
21		Low Pressure	45	19	30	8 to 10	MOV_2368.mp4	99.46	99.87	0.7	0.2	0.002	94.9
22		Dual HP/LP	44	6	55	8 to 10	MOV_2369.mp4	99.57	99.91	0.4	0.9	0.025	87.8
23		Low Pressure	68	6	55	12 to 14	MOV_2371.mp4	99.48	99.92	0.1	1.3	0.020	95.9
24		Dual HP/LP	43	7	49	14 to 16	MOV_2374.mp4	98.83	99.45	0.6	0.2	0.001	90.8
25		Dual HP/LP	48	8	42	8 to 10	MOV_2375.mp4	99.24	99.77	1.0	0.3	0.002	91.5
26		Low Pressure	46	7	44	14 to 16	MOV_2380.mp4	98.80	99.36	0.2	0.4	0.004	77.4
27		Dual HP/LP	42	7	42	18 to 20	MOV_2385.mp4	88.30	90.52	0.3	5.8	0.100	95.2
28		Dual HP/LP	42	8	43	18 to 20	MOV_2390.mp4	93.40	94.85	0.1	1.7	0.021	82.9
29		Low Pressure	46	8	44	18 to 20	MOV_2392.mp4	99.66	99.94	0.2	0.8	0.009	91.1
30		Dual HP/LP	37	10	41	16 to 18	MOV_2396.mp4	98.43	99.11	0.4	0.5	0.005	85.6
31		Low Pressure	43	10	41	22 to 24	MOV_2397.mp4	99.38	99.87	1.5	6.3	0.130	93.0
32		High Pressure	48	9	42	18 to 20	MOV_2398.mp4	99.67	99.95	0.3	1.0	0.013	89.8
33		Dual HP/LP	43	8	48	18 to 20	MOV_2400.mp4	96.17	97.20	0.2	5.5	0.088	95.7
34		Dual HP/LP	49	7	63	10 to 12	MOV_2401.mp4	99.88	99.95	0.2	12.4	0.257	97.2
35		High Pressure	50	7	68	4 to 6	MOV_2402.mp4	99.31	99.80	0.6	0.7	0.009	85.9
36		Low Pressure	40	7	68	4 to 6	MOV_2403.mp4	99.66	99.95	0.5	0.9	0.012	94.5
37		High Pressure	32	9	61	8 to 10	MOV_2404.mp4	99.52	99.91	0.8	0.2	0.003	92.7
38		Low Pressure	37	9	61	8 to 10	MOV_2405.mp4	99.40	99.89	0.5	0.6	0.007	96.2
39		Dual HP/LP	55	7	68	6 to 8	MOV_2406.mp4	99.23	99.78	0.2	1.0	0.010	85.7
40		High Pressure	52	6	67	8 to 10	MOV_2407.mp4	98.35	99.06	1.6	3.1	0.072	94.4
41		Low Pressure	60	6	67	8 to 10	MOV_2408.mp4	99.56	99.88	0.3	0.5	0.005	89.4
42		Dual HP/LP	68	2	79	10 to 12	MOV_2410.mp4	98.51	99.13	0.6	0.9	0.018	90.3
43		High Pressure	37	1	78	12 to 14	MOV_2411.mp4	99.26	99.71	0.4	0.8	0.009	88.9
44		Low Pressure	60	1	78	12 to 14	MOV_2412.mp4	97.88	98.66	0.1	1.1	0.011	94.7
45		Low Pressure	48	3	75	10 to 12	MOV_2413.mp4	98.87	99.48	0.9	0.3	0.004	95.9
46		Dual HP/LP	58	3	73	16 to 18	MOV_2416.mp4	98.66	99.31	0.5	9.0	0.181	97.7
47		Dual HP/LP	46	9	57	16 to 18	MOV_2418.mp4	97.12	97.96	0.8	0.6	0.008	86.5
48		Dual HP/LP	75	9	48	10 to 12	MOV_2419.mp4	97.37	98.22	0.2	7.2	0.134	89.1
49		Dual HP/LP	37	11	49	18 to 20	MOV_2420.mp4	98.55	99.23	1.2	0.3	0.003	86.4
50		High Pressure	40	7	43	12 to 14	MOV_2422.mp4	99.10	99.68	0.1	6.6	0.131	97.0
51		Dual HP/LP	43	12	43	30 to 32	MOV_2423.mp4	99.18	99.74	2.0	0.1	0.001	96.2
52		Low Pressure	50	8	29	26 to 28	MOV_2424.mp4	99.41	99.83	0.8	0.2	0.002	92.3
53		High Pressure	36	8	29	26 to 28	MOV_2425.mp4	99.27	99.80	0.1	0.1	0.000	82.3
54		Dual HP/LP	58	-1	68	10 to 12	MOV_2426.mp4	98.75	99.40	0.3	1.6	0.020	90.8
55		Dual HP /LP	49	-1	67	18 to 20	MOV_2427.mp4	98.43	99.10	0.6	1.6	0.037	86.2
56		Low Pressure	28	-2	72	14 to 16	MOV_2428.mp4	99.10	99.67	0.1	0.7	0.010	94.2
57		Dual HP/LP	61	-1	79	18 to 20	MOV_2429.mp4	97.10	98.00	0.2	2.2	0.031	80.9
58		Dual HP/LP	53	2	70	12 to 14	MOV_2430.mp4	99.13	99.63	0.4	1.3	0.018	85.9
59		Low Pressure	40	5	54	20 to 22	MOV_2432.mp4	99.08	99.67	0.2	0.9	0.013	92.3
60		Dual HP/ LP	70	5	50	16 to 18	MOV_2433.mp4	96.31	97.31	0.4	6.5	0.118	74.6
61		Dual HP/LP	42	3	51	18 to 20	MOV_2434.mp4	99.57	99.91	0.5	0.2	0.002	81.3
62		Low Pressure North	37	5	45	18 to 20	MOV_2435.mp4	99.00	99.55	0.5	0.7	0.010	91.5
63		Low Pressure South	43	5	45	18 to 20	MOV_2437.mp4	99.36	99.79	0.6	0.2	0.001	84.6
64		High Pressure	41	5	45	18 to 20	MOV_2438.mp4	99.03	99.56	3.0	0.6	0.009	95.0
65		High Pressure North	34	6	38	22 to 24	MOV_2439.mp4	99.68	99.94	0.3	0.9	0.014	90.6
66		High Pressure South	48	6	38	22 to 24	MOV_2440.mp4	99.75	99.95	0.6	0.9	0.014	89.8
67		Low Pressure	58	6	38	22 to 24	MOV_2441.mp4	99.19	99.71	0.2	0.2	0.002	84.2
68		Low Pressure	31	6	41	20 to 22	MOV_2442.mp4	99.64	99.94	0.4	1.3	0.028	93.4
69		High Pressure	32	9	34	10 to 12	MOV_2443.mp4	98.80	99.42	0.4	0.7	0.009	91.7
70		Low Pressure	39	9	34	10 to 12	MOV_2444.mp4	99.27	99.80	0.3	0.6	0.008	87.8
71		Low Pressure	37	7	37	16 to 18	MOV_2445.mp4	98.57	99.23	0.6	0.3	0.003	87.7
72		Dual HP/LP	68	8	36	20 to 22	MOV_2446.mp4	98.48	99.14	0.3	7.0	0.137	87.9
73		Dual HP/LP	58	11	32	6 to 8	MOV_2451.mp4	98.02	98.78	0.3	1.2	0.013	80.3
74		Dual HP/LP	91	7	42	16 to 18	MOV_2452.mp4	98.73	99.34	1.2	22.6	0.842	96.8
75		Low Pressure	39	-2	66	0 to 2	MOV_2453.mp4	98.29	99.01	1.0	0.7	0.012	95.8
76		High Pressure	30	-2	66	0 to 2	MOV_2454.mp4	99.43	99.87	0.7	0.3	0.004	94.9
77		Dual HP/ LP	76	2	55	0 to 2	MOV_2455.mp4	96.73	97.58	0.6	30.0	0.288	94.1
78		Dual HP/LP	83	3	59	0 to 2	MOV_2459.mp4	95.02	96.23	0.2	6.1	0.100	87.1
79		Dual HP/ LP	57	8	42	0 to 2	MOV_2460.mp4	99.74	99.95	1.1	0.2	0.001	95.3
80		Dual HP/LP	112	10	29	0 to 2	MOV_2461.mp4	99.44	99.90	0.5	53.6	1.098	96.8
81		Dual HP/LP	112	10	29	0 to 2	MOV_2462.mp4	99.36	99.82	0.5	61.2	1.239	96.5
82		Dual HP/LP	167	12	25	6 to 8	MOV_2463.mp4	99.20	99.72	0.7	53.8	1.104	96.9
83		Low Pressure	50	11	26	4 to 6	MOV_2464.mp4	96.50	97.49	0.1	1.6	0.025	88.8
84		Low Pressure South	37	13	25	4 to 6	MOV_2466.mp4	99.60	99.91	0.3	0.6	0.008	95.1
85		Low Pressure North	36	13	25	4 to 6	MOV_2467.mp4	99.18	99.69	0.5	0.4	0.005	93.7
86		Low Pressure South	20	13	25	4 to 6	MOV_2468.mp4	99.52	99.91	0.2	0.1	0.001	94.9
87		Low Pressure	59	14	23	4 to 6	MOV_2469.mp4	99.78	99.94	0.8	0.5	0.004	92.4
88		Low Pressure	40	14	23	4 to 6	MOV_2470.mp4	99.70	99.95	0.9	0.4	0.003	96.5
89		High Pressure	50	13	21	2 to 4	MOV_2471.mp4	99.21	99.69	1.0	9.4	0.265	94.9
90		High Pressure	63	13	21	2 to 4	MOV_2472.mp4	99.21	99.76	0.2	1.1	0.009	90.4
91		Dual HP/LP	42	15	18	2 to 4	MOV_2474.mp4	98.90	99.52	0.2	2.0	0.034	96.6
92		Low Pressure	30	12	17	8 to 10	MOV_2475.mp4	99.14	99.72	0.6	0.4	0.004	87.2

Flare Performance Metrics

VISR provides five flare performance metrics at a 1-second data interval:

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%. CE should not be confused with Destruction and Removal Efficiency (DRE). The difference between these two metrics is discussed in **Appendix C**. While CE is directly measured by the VISR method, DRE is derived using correlations established through extractive sampling as discussed in **Appendix C**.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 2 indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the VISR imager. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the VISR imager in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this study the flame size was above the minimum number of pixels for all measurements performed.

The second important DQI is the Smoke Index level. As the smoke index increases above 2.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Extractive testing shows that SI values above 3.0 may cause a small negative bias on the CE measurement (< 1%) and SI values above 5 may cause a significant negative bias to CE, as confirmed by testing with an extractive sampling method as a control. Any data points with a smoke index above 3 were removed from the summary tables and **Appendix A** results.

Observations

The following sections describe observations and comparisons derived from the dataset.

Distribution of Flare DRE

The majority of flares measured (90%) had a DRE greater than 98%, and 84% had a DRE greater than 99%. ***Figure 2*** shows the distribution of flare DRE measurements across the entire dataset.

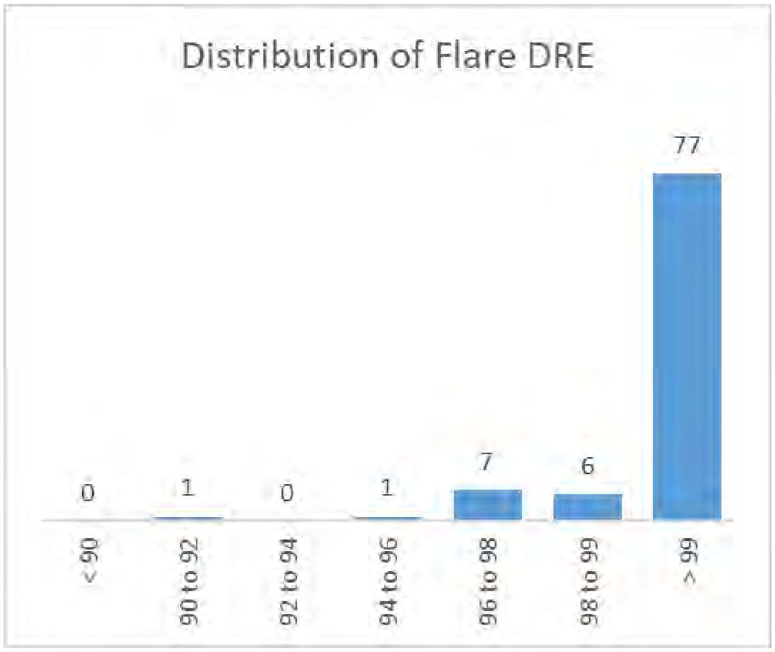

Figure 2: Distribution of Flare DRE measurements.

[redacted]

The lowest performing flare [redacted]
Figure 3 provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute measurement period was 90.82%.

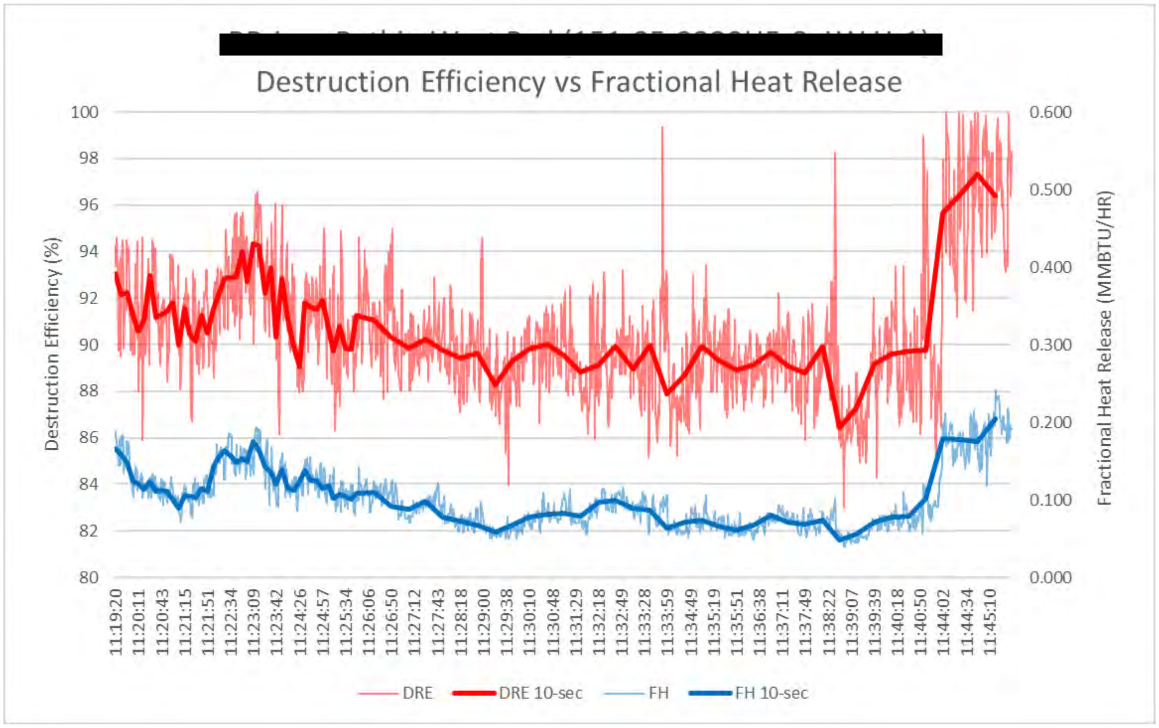

Figure 3: Destruction Efficiency vs. Fractional Heat Release for [redacted].

[redacted]

The flare with next lowest performance was the [redacted]). ***Figure 4*** provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute period was 94.85%.

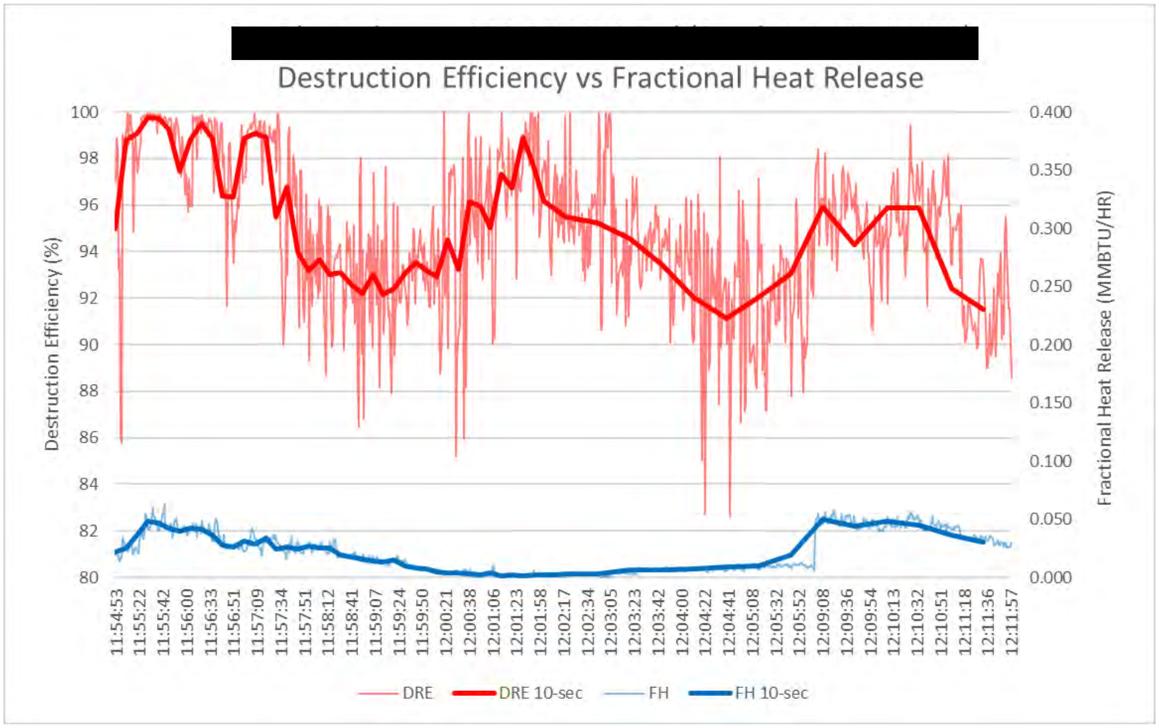

Figure 4: Destruction Efficiency vs. Fractional Heat Release for [redacted]

[redacted]

The flare with next lowest performance was the [redacted]-[redacted] ***Figure 5*** provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute period was 96.23%.

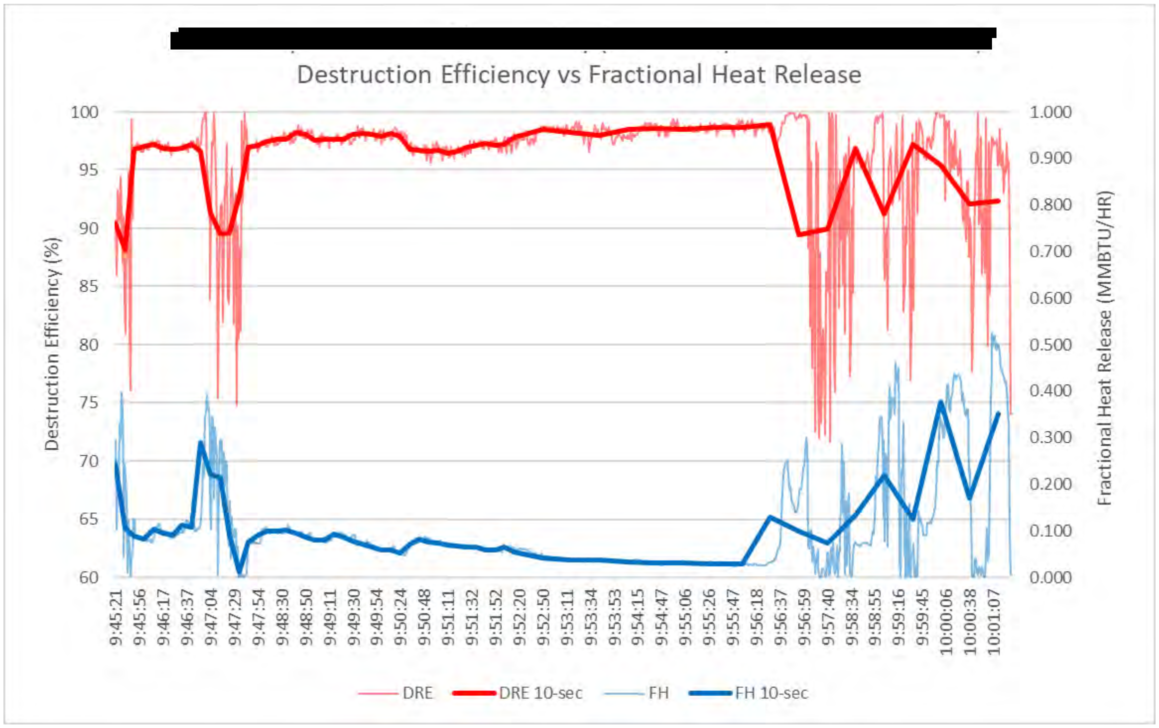

Figure 5: Destruction Efficiency vs. Fractional Heat Release and Smoke Index for [redacted]

Summary

In total, 92 flares across 67 sites were measured during the five-day study. The average DRE for all flares measured was 99.3%. Although there were a handful of flares with a DRE less than 98% (9 of 92), the majority of flares measured had a DRE which exceeded 99% (77 of 92). This data is consistent with prior studies in the area.

References

1. Yousheng Zeng, Jon Morris & Mark Dombrowski (2015) Validation of a new method for measuring and continuously monitoring the efficiency of industrial flares, Journal of the Air & Waste Management Association, 66:1, 76-86, DOI: 10.1080/10962247.2015.1114045

Appendix A: Results

Date/Time				Description				Conditions				FLIR Video	Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (Local)	End Time (Local)	Site Description	Latitude	Longitude	Flare Description	Distance (m)	Temp (°C)	RH (%)	Avg Wind Speed (mph)		CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	4/4/2022	8:04 AM	8:20 AM				High Pressure	46	3	72	4 to 6	MOV_2332.mp4	98.12	98.86	94.65	99.82	0.83	1.0	0.4	1.9	0.2	0.4	0.3	0.6	0.0	0.004	0.002	0.007	0.001	89.1	64.3	99.9	5.5
2	4/4/2022	8:23 AM	8:39 AM				Low Pressure	54	3	72	4 to 6	MOV_2334.mp4	99.68	99.94	98.53	99.99	0.16	0.3	0.2	1.1	0.1	0.3	0.2	0.7	0.0	0.004	0.002	0.006	0.001	96.8	42.6	100.0	4.0
3	4/4/2022	8:55 AM	9:10 AM				High Pressure	38	9	53	4 to 6	MOV_2337.mp4	99.50	99.93	98.90	99.87	0.16	0.8	0.4	1.1	0.1	1.4	1.1	1.7	0.1	0.021	0.016	0.027	0.001	95.5	86.7	100.0	2.3
4	4/4/2022	9:11 AM	9:26 AM				Low Pressure	46	9	53	4 to 6	MOV_2338.mp4	99.05	99.63	95.73	99.70	0.47	0.7	0.3	1.2	0.2	1.4	1.1	1.8	0.1	0.025	0.021	0.034	0.002	96.6	88.3	100.0	1.8
5	4/4/2022	9:40 AM	9:55 AM				High Pressure	44	8	59	8 to 10	MOV_2339.mp4	99.76	99.95	98.41	99.89	0.07	0.2	0.1	0.4	0.0	3.4	2.5	4.4	0.3	0.051	0.035	0.067	0.004	96.2	88.8	100.0	1.8
6	4/4/2022	9:56 AM	10:12 AM				Low Pressure	61	8	59	8 to 10	MOV_2340.mp4	99.35	99.83	92.91	99.79	0.48	0.6	0.1	1.6	0.2	0.5	0.1	1.1	0.2	0.004	0.001	0.012	0.003	93.7	76.6	99.9	3.6
7	4/4/2022	10:25 AM	10:40 AM				High Pressure	45	10	53	4 to 6	MOV_2341.mp4	99.54	99.92	97.53	99.96	0.20	0.5	0.2	1.1	0.1	0.6	0.3	1.1	0.2	0.007	0.002	0.015	0.002	81.8	31.1	99.9	10.9
8	4/4/2022	11:06 AM	11:21 AM				High Pressure	42	11	50	6 to 8	MOV_2342.mp4	99.03	99.61	97.79	99.95	0.36	0.4	0.2	0.8	0.1	1.8	0.7	2.6	0.4	0.028	0.012	0.041	0.006	93.6	68.8	100.0	4.1
9	4/4/2022	11:23 AM	11:38 AM				Low Pressure	53	11	50	6 to 8	MOV_2344.mp4	99.36	99.86	98.34	99.84	0.24	0.4	0.1	1.5	0.2	0.9	0.3	1.6	0.2	0.011	0.004	0.022	0.004	91.0	69.9	100.0	5.4
10	4/4/2022	12:11 PM	12:26 PM				Low Pressure	44	14	39	12 to 14	MOV_2348.mp4	98.90	99.52	97.21	99.74	0.40	0.6	0.3	1.4	0.2	0.7	0.3	1.4	0.2	0.010	0.004	0.020	0.003	93.4	36.5	100.0	4.6
11	4/4/2022	12:44 PM	1:00 PM				HP/LP Assisted	49	14	38	14 to 16	MOV_2351.mp4	97.66	98.47	85.49	99.57	1.81	0.2	0.1	3.4	0.2	5.5	2.6	56.4	3.2	0.088	0.030	0.315	0.017	97.4	0.1	100.0	3.4
12	4/4/2022	1:15 PM	1:31 PM				High Pressure South	49	14	38	14 to 16	MOV_2354.mp4	98.59	99.23	84.95	99.99	1.29	1.5	0.4	3.2	0.5	3.4	0.6	11.7	1.9	0.092	0.012	0.242	0.063	92.5	21.1	100.0	5.7
13	4/4/2022	1:33 PM	1:48 PM				Low Pressure South	52	14	38	14 to 16	MOV_2356.mp4	99.46	99.89	98.42	99.96	0.24	0.7	0.3	1.3	0.1	0.1	0.1	0.3	0.0	0.001	0.001	0.002	0.000	92.1	30.6	100.0	4.5
14	4/4/2022	1:56 PM	2:11 PM				High Pressure North	38	14	38	14 to 16	MOV_2358.mp4	98.88	99.50	97.34	99.73	0.45	0.1	0.0	0.1	0.0	0.3	0.1	0.7	0.1	0.003	0.001	0.008	0.001	92.6	72.7	100.0	4.1
15	4/4/2022	2:12 PM	2:27 PM				Low Pressure North	32	14	38	14 to 16	MOV_2359.mp4	99.49	99.85	97.81	99.99	0.38	0.3	0.2	0.8	0.1	0.1	0.1	0.2	0.0	0.001	0.001	0.002	0.000	89.4	16.3	100.0	6.1
16	4/4/2022	2:41 PM	2:57 PM				High Pressure	37	18	32	10 to 12	MOV_2362.mp4	98.04	98.79	96.29	99.39	0.51	0.4	0.2	0.9	0.1	1.2	0.6	2.3	0.3	0.020	0.008	0.041	0.006	89.9	64.2	99.9	5.7
17	4/4/2022	2:57 PM	3:12 PM				Low Pressure	45	18	32	10 to 12	MOV_2363.mp4	98.59	99.26	96.80	99.70	0.46	0.7	0.2	2.2	0.4	0.1	0.1	0.3	0.0	0.001	0.000	0.003	0.001	94.5	77.3	100.0	3.2
18	4/4/2022	3:32 PM	3:47 PM				High Pressure	34	19	32	12 to 14	MOV_2365.mp4	98.90	99.51	96.36	99.85	0.46	0.6	0.4	1.0	0.1	0.2	0.1	0.3	0.0	0.002	0.001	0.002	0.000	95.2	84.9	99.9	2.3
19	4/4/2022	3:48 PM	4:07 PM				Low Pressure	38	19	32	12 to 14	MOV_2366.mp4	98.46	99.15	96.42	99.56	0.52	0.1	0.1	0.2	0.0	0.5	0.2	1.1	0.2	0.007	0.002	0.016	0.003	93.3	60.4	99.9	4.5
20	4/4/2022	4:22 PM	4:37 PM				High Pressure	37	19	30	8 to 10	MOV_2367.mp4	98.68	99.34	96.70	99.74	0.52	0.2	0.1	0.6	0.0	3.2	2.3	4.2	0.3	0.056	0.037	0.076	0.007	96.7	86.3	100.0	1.9
21	4/4/2022	4:38 PM	4:53 PM				Low Pressure	45	19	30	8 to 10	MOV_2368.mp4	99.46	99.87	98.40	99.94	0.28	0.7	0.3	1.6	0.3	0.2	0.1	0.5	0.1	0.002	0.000	0.006	0.002	94.9	84.1	100.0	2.4
22	4/5/2022	8:07 AM	8:22 AM				Dual HP/LP	44	6	55	8 to 10	MOV_2369.mp4	99.57	99.91	96.62	99.99	0.32	0.4	0.2	3.7	0.3	0.9	0.2	17.8	2.7	0.025	0.002	0.881	0.118	87.8	0.1	99.3	6.0
23	4/5/2022	9:04 AM	9:19 AM				Low Pressure	68	6	55	12 to 14	MOV_2371.mp4	99.48	99.92	98.59	99.87	0.17	0.1	0.1	0.2	0.0	1.3	0.8	1.8	0.2	0.020	0.013	0.025	0.002	95.9	55.8	100.0	3.2
24	4/5/2022	9:35 AM	9:50 AM				Dual HP/LP	43	7	49	14 to 16	MOV_2374.mp4	98.83	99.45	96.35	99.88	0.52	0.6	0.3	1.3	0.2	0.2	0.1	0.5	0.1	0.001	0.001	0.005	0.001	90.8	0.1	99.9	6.6
25	4/5/2022	10:02 AM	10:17 AM				Dual HP/LP	48	8	42	8 to 10	MOV_2375.mp4	99.24	99.77	97.85	99.88	0.33	1.0	0.4	2.0	0.3	0.3	0.2	0.6	0.1	0.002	0.001	0.005	0.001	91.5	62.5	99.7	4.7
26	4/5/2022	10:46 AM	11:01 AM				Low Pressure	46	7	44	14 to 16	MOV_2380.mp4	98.80	99.36	94.26	99.99	0.97	0.2	0.1	1.2	0.1	0.4	0.1	1.1	0.2	0.004	0.000	0.014	0.002	77.4	27.7	100.0	12.2
27	4/5/2022	11:19 AM	11:40 AM				Dual HP/LP	42	7	42	18 to 20	MOV_2385.mp4	88.30	90.52	79.42	99.65	3.24	0.3	0.1	1.1	0.2	5.8	3.0	9.8	1.3	0.100	0.040	0.241	0.039	95.2	76.8	99.9	3.1
28	4/5/2022	11:55 AM	12:12 PM				Dual HP/LP	42	8	43	18 to 20	MOV_2390.mp4	93.40	94.85	78.99	99.99	3.78	0.1	0.0	0.9	0.1	1.7	0.1	4.6	1.2	0.021	0.000	0.063	0.017	82.9	0.1	99.9	19.1
29	4/5/2022	12:26 PM	12:41 PM				Low Pressure	46	8	44	18 to 20	MOV_2392.mp4	99.66	99.94	98.64	99.99	0.16	0.2	0.1	0.5	0.0	0.8	0.4	1.2	0.2	0.009	0.003	0.015	0.002	91.1	62.7	100.0	5.8
30	4/5/2022	12:53 PM	1:08 PM				Dual HP/LP	37	10	41	16 to 18	MOV_2396.mp4	98.43	99.11	87.37	99.87	1.02	0.4	0.1	1.0	0.1	0.5	0.2	1.5	0.2	0.005	0.002	0.016	0.002	85.6	3.8	99.9	10.6
31	4/5/2022	1:26 PM	1:41 PM				Low Pressure	43	10	41	22 to 24	MOV_2397.mp4	99.38	99.87	98.10	99.84	0.26	1.5	0.4	3.5	0.5	6.3	2.6	11.7	1.3	0.130	0.042	0.259	0.033	93.0	2.1	99.9	5.6
32	4/5/2022	1:57 PM	2:12 PM				High Pressure	48	9	42	18 to 20	MOV_2398.mp4	99.67	99.95	99.03	99.96	0.12	0.3	0.2	1.1	0.1	1.0	0.6	1.4	0.1	0.013	0.007	0.021	0.002	89.8	68.7	99.9	4.6
33	4/5/2022	2:26 PM	2:42 PM				Dual HP/LP	43	8	48	18 to 20	MOV_2400.mp4	96.17	97.20	87.69	99.03	1.56	0.2	0.1	0.3	0.0	5.5	3.9	7.9	0.6	0.088	0.068	0.127	0.009	95.7	54.4	100.0	2.9
34	4/5/2022	3:16 PM	3:31 PM				Dual HP/LP	49	7	63	10 to 12	MOV_2401.mp4	99.88	99.95	99.19	99.99	0.08	0.2	0.1	0.5	0.0	12.4	9.8	14.6	0.8	0.257	0.180	0.321	0.026	97.2	59.5	100.0	1.8
35	4/5/2022	3:46 PM	4:01 PM				High Pressure	50	7	68	4 to 6	MOV_2402.mp4	99.31	99.80	96.65	99.94	0.36	0.6	0.2	1.8	0.2	0.7	0.3	1.4	0.2	0.009	0.003	0.019	0.003	85.9	27.1	99.8	9.8
36	4/5/2022	4:02 PM	4:17 PM				Low Pressure	40	7	68	4 to 6	MOV_2403.mp4	99.66	99.95	98.94	99.99	0.15	0.5	0.2	1.5	0.2	0.9	0.6	1.3	0.1	0.012	0.009	0.016	0.001	94.5	54.7	100.0	4.6
37	4/5/2022	4:31 PM	4:46 PM				High Pressure	32	9	61	8 to 10	MOV_2404.mp4	99.52	99.91	97.99	99.93	0.24	0.8	0.4	1.2	0.1	0.2	0.1	0.4	0.0	0.003	0.001	0.005	0.001	92.7	64.7	100.0	5.1
38	4/5/2022	4:47 PM	5:02 PM				Low Pressure	37	9	61	8 to 10	MOV_2405.mp4	99.40	99.89	98.85	99.75	0.16	0.5	0.3	1.0	0.1	0.6	0.4	0.9	0.1	0.007	0.004	0.011	0.001	96.2	82.6	100.0	2.1
39	4/5/2022	5:13 PM	5:28 PM				Dual HP/LP	55	7	68	6 to 8	MOV_2406.mp4	99.23	99.78	97.26	99.88	0.31	0.2	0.1	0.4	0.0	1.0	0.7	1.4	0.1	0.010	0.007	0.016	0.001	85.7	55.2	100.0	6.9
40	4/5/2022	5:40 PM	5:55 PM				High Pressure	52	6	67	8 to 10	MOV_2407.mp4	98.35	99.06	91.53	99.64	0.79	1.6	0.8	2.3	0.3	3.1	1.5	26.3	1.0	0.072	0.042	0.108	0.010	94.4	28.5	100.0	4.8
41	4/5/2022	5:55 PM	6:10 PM				Low Pressure	60	6	67	8 to 10	MOV_2408.mp4	99.56	99.88	93.28	99.99	0.46	0.3	0.2	1.4	0.2	0.5	0.1	1.2	0.3	0.005	0.000	0.012	0.003	89.4	36.5	99.8	6.9
42	4/6/2022	8:22 AM	8:37 AM				Dual HP/LP	68	2	79	10 to 12	MOV_2410.mp4	98.51	99.13	91.86	99.99	1.21	0.6	0.1	1.7	0.3	0.9	0.2	13.6	2.0	0.018	0.001	0.417	0.060	90.3	0.1	100.0	8.6
43	4/6/2022	8:51 AM	9:06 AM				High Pressure	37	1	78	12 to 14	MOV_2411.mp4	99.26	99.71	95.26	99.99	0.57	0.4	0.1	0.7	0.1	0.8	0.3	1.3	0.1	0.009	0.002	0.017	0.002	88.9	68.3	100.0	5.7
44	4/6/2022	9:08 AM	9:23 AM				Low Pressure	60	1	78	12 to 14	MOV_2412.mp4	97.88	98.66	95.20	99.05	0.56	0.1	0.1	0.7	0.0	1.1	0.8	1.9	0.1	0.011	0.007	0.017	0.001	94.7	59.2	100.0	4.7
45	4/6/2022	9:40 AM	9:55 AM				Low Pressure	48	3	75	10 to 12	MOV_2413.mp4	98.87	99.48	96.71	99.82	0.52	0.9	0.4	2.1	0.3	0.3	0.1	0.6	0.1	0.004	0.002	0.007	0.001	95.9	87.8	100.0	2.0
46	4/6/2022	10:46 AM	11:01 AM				Dual HP/LP	58	3	73	16 to 18	MOV_2416.mp4	98.66	99.31	95.78	99.92	0.61	0.5	0.2	1.2	0.1	9.0	6.5	21.7	2.1	0.181	0.126	0.523	0.056	97.7	91.7	100.0	1.3
47	4/6/2022	11:44 AM	12:03 PM				Dual HP/LP	46	9	57	16 to 18	MOV_2418.mp4	97.12	97.96	85.06	99.99	3.18	0.8	0.1	3.7	0.7	0.6	0.1	6.5	0.8	0.008	0.000	0.140	0.014	86.5	0.1	100.0	14.4
48	4/6/2022	12:17 PM	12:32 PM				Dual HP/LP	75	9	48	10 to 12	MOV_2419.mp4	97.37	98.22	91.73	99.68	1.23	0.2	0.1	0.8	0.1	7.2	0.2	25.4	6.0	0.134	0.001	0.669	0.143	89.1	25.4	99.9	11.9
49	4/6/2022	12:58 PM	1:13 PM				Dual HP/LP	37	11	49	18 to 20	MOV_2420.mp4	98.55	99.23	96.83	99.75	0.48	1.2	0.6	2.2	0.3	0.3	0.2	0.4	0.0	0.003	0.002	0.005	0.001	86.4	65.1	100.0	6.6
50	4/6/2022	2:14 PM	2:29 PM				High Pressure	40	7	43	12 to 14	MOV_2422.mp4	99.10	99.68	97.87	99.85	0.28	0.1	0.1	0.3	0.0	6.6	4.2	8.5	0.6	0.131	0.090	0.179	0.013	97.0	86.5	100.0	2.2
51	4/6/2022	3:27 PM	3:42 PM				Dual HP/LP	43	12	43	30 to 32	MOV_2423.mp4	99.18	99.74	97.84	99.81	0.31	2.0	1.2	3.3	0.3	0.1	0.1	0.5	0.0	0.001	0.001	0.003	0.000	96.2	6.4	100.0	7.0
52	4/6/2022	4:01 PM	4:16 PM				Low Pressure	50	8	29	26 to 28	MOV_2424.mp4	99.41	99.83	97.99	99.99	0.37	0.8	0.4	1.9	0.2	0.2	0.1	0.4	0.0	0.002	0.001	0.004	0.000	92.3	77.4	100.0	4.1
53	4/6/2022	4:17 PM	4:22 PM				High Pressure	36	8	29	26 to 28	MOV_2425.mp4	99.27	99.80	98.23	99.95	0.27	0.1	0.0	0.2	0.0	0.1	0.0	0.1	0.0	0.000	0.000	0.001	0.000	82.3	53.7	99.6	8.6
54	4/7/2022	7:33 AM	7:48 AM				Dual HP/LP	58	-1	68	10 to 12	MOV_2426.mp4	98.75	99.40	96.77	99.56	0.25	0.3	0.2	0.7	0.1	1.6	1.1	6.4	0.6	0.020	0.010	0.091	0.008	90.8	69.3	100.0	4.9
55	4/7/2022	8:05 AM	8:20 AM				Dual HP/LP	49	-1	67	18 to 20	MOV_2427.mp4	98.43	99.10	95.05	99.99	0.70	0.6	0.1	2.4	0.5	1.6	0.2	9.7	1.7	0.037	0.001	0.298	0.060	86.2	0.1	99.9	8.9
56	4/7/2022	8:32 AM	8:47 AM				Low Pressure	28	-2	72	14 to 16	MOV_2428.mp4	99.10	99.67	97.47	99.86	0.39	0.1	0.1	0.1	0.0	0.7	0.3	1.2	0.2	0.010	0.004	0.022	0.003	94.2	82.2	100.0	3.2
57	4/7/2022	8:59 AM	9:14 AM				Dual HP/LP	61	-1	79	18 to 20	MOV_2429.mp4	97.10	98.00	94.26	99.35	0.79	0.2	0.1	0.3	0.0	2.2	0.5	4.6	0.7	0.031	0.004	0.087	0.014	80.9	0.1	100.0	15.8
58	4/7/2022	9:24 AM	9:39 AM				Dual HP/LP	53	2	70	12 to 14	MOV_2430.mp4	99.13	99.63	95.71	99.99	0.54	0.4	0.1	1.0	0.1	1.3	0.8	1.8	0.2	0.018	0.008	0.029	0.003	85.9	61.0	99.9	6.8
59	4/7/2022	10:00 AM	10:15 AM				Low Pressure	40	5	54	20 to 22	MOV_2432.mp4	99.08	99.67	97.97	99.68	0.27	0.2	0.1	0.4	0.0	0.9	0.5	1.7	0.2	0.013	0.007	0.023	0.003	92.3	74.8	99.9	4.3
60	4/7/2022	10:30 AM	10:45 AM				Dual HP/LP	70	5	50	16 to 18	MOV_2433.mp4	96.31	97.31	70.17	99.87	3.27	0.4	0.1	2.3	0.3	6.5	0.1	24.5	7.5	0.118	0.000	0.643	0.149	74.6	0.1	99.7	22.1
61	4/7/2022	10:55 AM	11:10 AM				Dual HP/LP	42	3	51	18 to 20	MOV_2434.mp4	99.57	99.91	98.26	99.99	0.29	0.5	0.1	2.4	0.3	0.2	0.0	0.6	0.1	0.002	0.000	0.007	0.001	81.3	25.6	100.0	10.3
62	4/7/2022	11:24 AM	11:39 AM				Low Pressure North	37	5	45	18 to 20	MOV_2435.mp4	99.00	99.55	96.22	99.99	0.56	0.5	0.2	1.3	0.1	0.7	0.4	1.0	0.1	0.010	0.006	0.014	0.001	91.5	67.8	99.9	4.4
63	4/7/2022	11:41 AM	11:56 AM				Low Pressure South	43	5	45	18 to 20	MOV_2437.mp4	99.36	99.79	96.54	99.99	0.49	0.6	0.1	1.8	0.3	0.2	0.1	0.8	0.1	0.001	0.000	0.008	0.001	84.6	0.1	100.0	11.6
64	4/7/2022	11:58 AM	12:13 PM				High Pressure	41	5	45	18 to 20	MOV_2438.mp4	99.03	99.56	97.11	99.99	0.64	3.0	0.1	7.0	1.7	0.6	0.1	6.0	1.1	0.009	0.001	0.117	0.020	95.0	62.2	100.0	4.2
65	4/7/2022	12:33 PM	12:48 PM				High Pressure North	34	6	38	22 to 24	MOV_2439.mp4	99.68	99.94	98.36	99.99	0.23	0.3	0.2	0.6	0.1	0.9	0.5	1.5	0.2	0.014	0.004	0.031	0.005	90.6	49.5	100.0	5.0
66	4/7/2022	12:49 PM	1:04 PM				High Pressure South	48	6	38	22 to 24	MOV_2440.mp4	99.75	99.95	99.30	99.99	0.09	0.6	0.2	0.9	0.1	0.9	0.5	1.9	0.2	0.014	0.005	0.034	0.005	89.8	59.8	99.9	5.7
67	4/7/2022	1:08 PM	1:23 PM				Low Pressure	58	6	38	22 to 24	MOV_2441.mp4	99.19	99.71	97.04	99.91	0.46	0.2	0.1	0.5	0.1	0.2	0.1	0.8	0.1	0.002	0.001	0.010	0.002	84.2	35.5	99.9	8.3
68	4/7/2022	1:37 PM	1:52 PM				Low Pressure	31	6	41	20 to 22	MOV_2442.mp4	99.64	99.94	98.71	99.98	0.18	0.4	0.1	1.2	0.2	1.3	0.4	3.3	0.5	0.028	0.008	0.062	0.013	93.4	59.5	100.0	4.8
69	4/7/2022	2:21 PM	2:36 PM				High Pressure	32	9	34	10 to 12	MOV_2443.mp4	98.80	99.42	94.76	99.99	0.54	0.4	0.2	0.8	0.1	0.7	0.3	1.2	0.1	0.009	0.003	0.018	0.002	91.7	74.7	100.0	4.7
70	4/7/2022	2:37 PM	2:52 PM				Low Pressure	39	9	34	10 to 12	MOV_2444.mp4	99.27	99.80	92.67	99.96	0.41	0.3	0.1	1.1	0.1	0.6	0.2	1.0	0.1	0.008	0.002	0.014	0.002	87.8	31.9	100.0	7.6
71	4/7/2022	3:13 PM	3:28 PM				Low Pressure	37	7	37	16 to 18	MOV_2445.mp4	98.57	99.23	96.53	99.87	0.46	0.6	0.2	1.3	0.2	0.3	0.1	0.7	0.1	0.003	0.001	0.010	0.001	87.7	32.2	99.8	6.5
72	4/7/2022	3:49 PM	4:04 PM				Dual HP/LP	68	8	36	20 to 22	MOV_2446.mp4	98.48	99.14	92.52	99.99	0.90	0.3	0.1	1.5	0.2	7.0	0.2	41.4	8.5	0.137	0.001	0.663	0.185	87.9	18.3	99.9	10.2
73	4/7/2022	4:54 PM	5:09 PM				Dual HP/LP	58	11	32	6 to 8	MOV_2451.mp4	98.02	98.78	95.48	99.79	0.97	0.3	0.1	0.9	0.1	1.2	0.1	2.8	0.5	0.013	0.001	0.032	0.006	80.3	0.1	99.3	11.9
74	4/7/2022	5:26 PM	5:41 PM				Dual HP/LP	91	7	42	16 to 18	MOV_2452.mp4	98.73	99.34	81.51	99.95	1.90	1.2	0.4	3.1	0.6	22.6	9.1	148.3	7.9	0.842	0.334	1.423	0.204	96.8	47.8	100.0	2.9
75	4/8/2022	8:08 AM	8:23 AM				Low Pressure	39	-2	66	0 to 2	MOV_2453.mp4	98.29	99.01	96.13	99.42	0.49	1.0	0.6	1.4	0.1	0.7	0.5	0.9	0.1	0.012	0.010	0.015	0.001	95.8	85.8	100.0	1.9
76	4/8/2022	8:24 AM	8:39 AM				High Pressure	30	-2	66	0 to 2	MOV_2454.mp4	99.43	99.87	98.58	99.92	0.25	0.7	0.3	1.8	0.3	0.3	0.1	0.5	0.1	0.004	0.001	0.006	0.001	94.9	71.6	100.0	3.6
77	4/8/2022	9:17 AM	9:35 AM				Dual HP/LP	76	2	55	0 to 2	MOV_2455.mp4	96.73	97.58	62.85	99.99	7.52	0.6	0.1	4.1	0.9	30.0	4.1	189.5	47.2	0.288	0.034	2.630	0.327	94.1	11.0	100.0	9.7
78	4/8/2022	9:45 AM	10:01 AM				Dual HP/LP	83	3	59	0 to 2	MOV_2459.mp4	95.02	96.23	66.03	99.91	5.35	0.2	0.1	2.0	0.3	6.1	0.2	24.0	4.8	0.100	0.001	0.525	0.104	87.1	0.1	100.0	23.7
79	4/8/2022	10:16 AM	10:26 AM				Dual HP/LP	57	8	42	0 to 2	MOV_2460.mp4	99.74	99.95	99.24	99.99	0.15	1.1	0.8	2.0	0.2	0.2	0.1	0.4	0.0	0.001	0.001	0.002	0.000	95.3	6.8	100.0	7.6
80	4/8/2022	10:56 AM	11:11 AM				Dual HP/LP	112	10	29	0 to 2	MOV_2461.mp4	99.44	99.90	96.64	99.97	0.24	0.5	0.4	0.8	0.1	53.6	38.4	71.4	4.8	1.098	0.828	1.358	0.102	96.8	84.8	100.0	1.7
81	4/8/2022	11:26 AM	11:44 AM				Dual HP/LP	112	10	29	0 to 2	MOV_2462.mp4	99.36	99.82	94.10	99.95	0.42	0.5	0.2	2.2	0.1	61.2	23.2	171.8	7.0	1.239	0.291	1.633	0.149	96.5	0.1	100.0	4.1
82	4/8/2022	11:55 AM	12:10 PM				Dual HP/LP	167	12	25	6 to 8	MOV_2463.mp4	99.20	99.72	87.28	99.86	1.10	0.7	0.3	1.4	0.3	53.8	31.5	186.2	12.0	1.104	0.591	1.875	0.306	96.9	45.4	99.9	2.8
83	4/8/2022	12:26 PM	12:41 PM				Low Pressure	50	11	26	4 to 6	MOV_2464.mp4	96.50	97.49	91.54	99.40	1.30	0.1	0.1	0.2	0.0	1.6	0.8	2.6	0.3	0.025	0.013	0.039	0.006	88.8	68.3	99.9	5.1
84	4/8/2022	1:01 PM	1:16 PM				Low Pressure South	37	13	25	4 to 6	MOV_2466.mp4	99.60	99.91	98.56	99.99	0.26	0.3	0.0	1.0	0.2	0.6	0.2	1.1	0.2	0.008	0.002	0.017	0.003	95.1	75.2	99.9	3.1
85	4/8/2022	1:16 PM	1:31 PM				Low Pressure North	36	13	25	4 to 6	MOV_2467.mp4	99.18	99.69	94.35	99.92	0.64	0.5	0.1	1.2	0.2	0.4	0.1	1.2	0.3	0.005	0.001	0.017	0.004	93.7	69.5	100.0	4.2
86	4/8/2022	1:34 PM	1:49 PM				Low Pressure South	20	13	25	4 to 6	MOV_2468.mp4	99.52	99.91	98.47	99.96	0.22	0.2	0.1	0.4	0.0	0.1	0.1	0.2	0.0	0.001	0.001	0.002	0.000	94.9	66.2	99.9	3.1
87	4/8/2022	2:07 PM	2:22 PM				Low Pressure	59	14	23	4 to 6	MOV_2469.mp4	99.78	99.94	98.61	99.99	0.20	0.8	0.3	1.2	0.2	0.5	0.3	1.2	0.2	0.004	0.003	0.011	0.001	92.4	54.4	100.0	6.9
88	4/8/2022	2:23 PM	2:38 PM				Low Pressure	40	14	23	4 to 6	MOV_2470.mp4	99.70	99.95	98.88	99.94	0.12	0.9	0.5	1.2	0.1	0.4	0.3	0.5	0.0	0.003	0.002	0.005	0.000	96.5	14.6	100.0	3.2
89	4/8/2022	3:02 PM	3:17 PM				High Pressure	50	13	21	2 to 4	MOV_2471.mp4	99.21	99.69	88.08	99.99	0.85	1.0	0.4	2.4	0.5	9.4	5.7	26.2	1.7	0.265	0.142	0.406	0.044	94.9	58.3	99.9	4.0
90	4/8/2022	3:19 PM	3:34 PM				High Pressure	63	13	21	2 to 4	MOV_2472.mp4	99.21	99.76	98.03	99.94	0.28	0.2	0.1	0.9	0.1	1.1	0.4	4.6	0.5	0.009	0.004	0.023	0.003	90.4	51.1	100.0	6.4
91	4/8/2022	4:16 PM	4:31 PM				Dual HP/LP	42	15	18	2 to 4	MOV_2474.mp4	98.90	99.52	97.75	99.81	0.34	0.2	0.1	1.8	0.1	2.0	1.2	2.9	0.3	0.034	0.022	0.045	0.004	96.6	42.3	100.0	2.9
92	4/8/2022	4:49 PM	5:04 PM				Low Pressure	30	12	17	8 to 10	MOV_2475.mp4	99.14	99.72	97.70	99.69	0.26	0.6	0.3	1.2	0.1	0.4	0.2	0.6	0.1	0.004	0.002	0.007	0.001	87.2	66.9	99.9	6.1

Appendix B: Validation of the VISR method

The VISR method has been extensively tested using extractive sampling as a control method. The largest blind test was conducted by the Petroleum Environmental Research Forum (PERF), a non-profit organization created to provide a stimulus to and a forum for the collection, exchange, and analysis of research information relating to the petroleum industry. PERF project 2014-10 (Test) was created by participating PERF companies to provide a test platform for various developers/vendors of flare remote sensing technologies (Invitees) to participate in a blind test to evaluate the effectiveness of each technology. The test was administered by John Zink at their test facility in Tulsa, Oklahoma, USA. [redacted] sponsoring PERF companies and Providence Photonics was one of the vendors participating in the PERF test. The results of the PERF test have now been released to the public.

The PERF test consisted of 43 individual test points. Each test point was measured with an extractive system suspended over the flame, as shown in *Figure 15*. With the exception of 3 test points provided as calibration data (per test protocol), the test was completely blind for the participants. The flare performance (Combustion Efficiency), flow rate and fuel composition were not shared with the participants until after their individual results were submitted.

The VISR method performed quite well in the PERF test. *Figure 16* below shows the VISR results compared to the control method (extractive results) across the 43 test points. Overall, the VISR result was within 1% of the extractive result and the accuracy was even better for the higher CE range (above 95%).

Figure 15. VISR method demonstrated as part of the PERF remote flare monitoring blind testing.

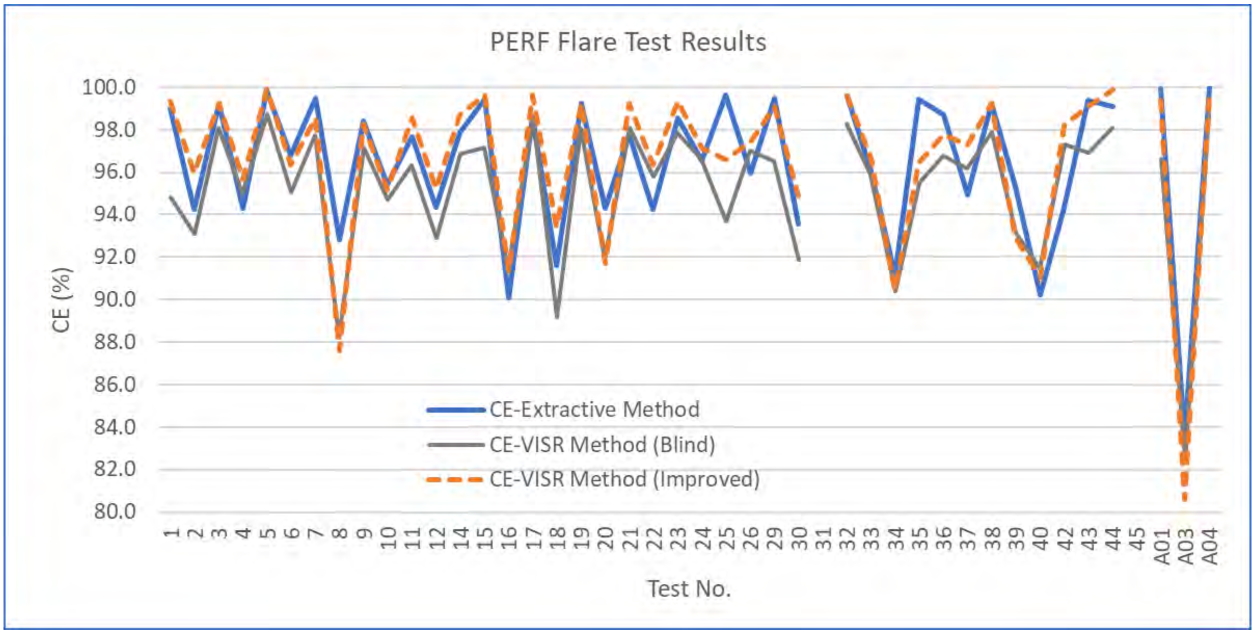

Figure 16. PERF test results, VISR (remote) vs. Extractive.

Note that the CE definition used by VISR was slightly different than what was used for the PERF extractive results. *Equation 1* below shows the calculation used to determine CE from the extractive results:

$$CE\ (\%) = \frac{CO_2(vol\%)}{CO_2(vol\%) + \frac{[CO(ppmvd) + 3\ \times THC(ppmvd)]}{10000}} \times 100$$

Equation 1

The VISR method uses the same equation but excludes the CO component. Extractive testing (including the PERF study) conducted by Providence Photonics, it was shown that the concentration of CO in the combustion plume (especially when CE is greater than 95%) is orders of magnitude lower than either CO2 or THC. Therefore, the effect of excluding CO from the CE equation is negligible.

Some definitions of CE also include soot (IE carbon) in the denominator, which means the presence of smoke will tend to lower CE. The VISR method does not measure carbon soot when determining CE, which is consistent with the definition of CE in a regulatory context.

A systematic negative bias of -0.8% was observed in the VISR results when compared to the extractive results from the PERF test. Providence Photonics has continued developing the CE algorithm since the PERF testing and believes that the systematic bias has been removed. This was confirmed by Providence Photonics by re-running the PERF data with the latest VISR algorithm. More information regarding the validation testing performed on the VISR method can be found in the PERF Report.

Another set of extractive testing was conducted at Zeeco's test facility in Tulsa, Oklahoma, USA and is discussed in a peer reviewed journal article[1].

Appendix C: Combustion Efficiency Versus Destruction Efficiency

With respect to emissions calculations or GHG reporting, it is important to consider the difference between combustion efficiency (CE) and destruction efficiency (DE). The VISR method measures CE, which is a measure of the efficiency of the flame to convert hydrocarbons into carbon dioxide and water. If the combustion efficiency is 100%, then all of the hydrocarbons have been oxidized all the way to carbon dioxide, leaving no hydrocarbons in the post combustion plume. CE will be reduced as the percentage of hydrocarbon in the post combustion plume increases. Destruction efficiency is a measure of the percentage of a compound that is destroyed (IE converted into another form), but not necessarily oxidized to the ultimate combustion product of carbon dioxide and water. In this case, it represents the percentage of hydrocarbons destroyed. The hydrocarbons could be converted to carbon dioxide, carbon monoxide, soot or another compound. As a result, DE is typically higher than CE. For emission inventory purposes, flares are generally deemed to have a DE of 98%, meaning 98% of the hydrocarbons sent to the flare are converted into another form. There is no quantitative method to convert the VISR CE data to DE, however we do have some points of reference. The US EPA Refinery Sector Rule (40 CFR 63.670 (r) equates a CE of 96.5% to a DE of 98%. The rule references the John Zink combustion handbook (Baukal, 2001).

In addition, there have been two major studies which have measured both CE and DE with extractive sampling: the 2010 TCEQ Study and the 2016 PERF Study. Both of these studies were conducted at John Zink's research facility in Tulsa, Oklahoma. Taken collectively, these studies provide 71 individual measurements of CE and DE. *Figure 8* below shows the relationship between CE and DE from these two studies.

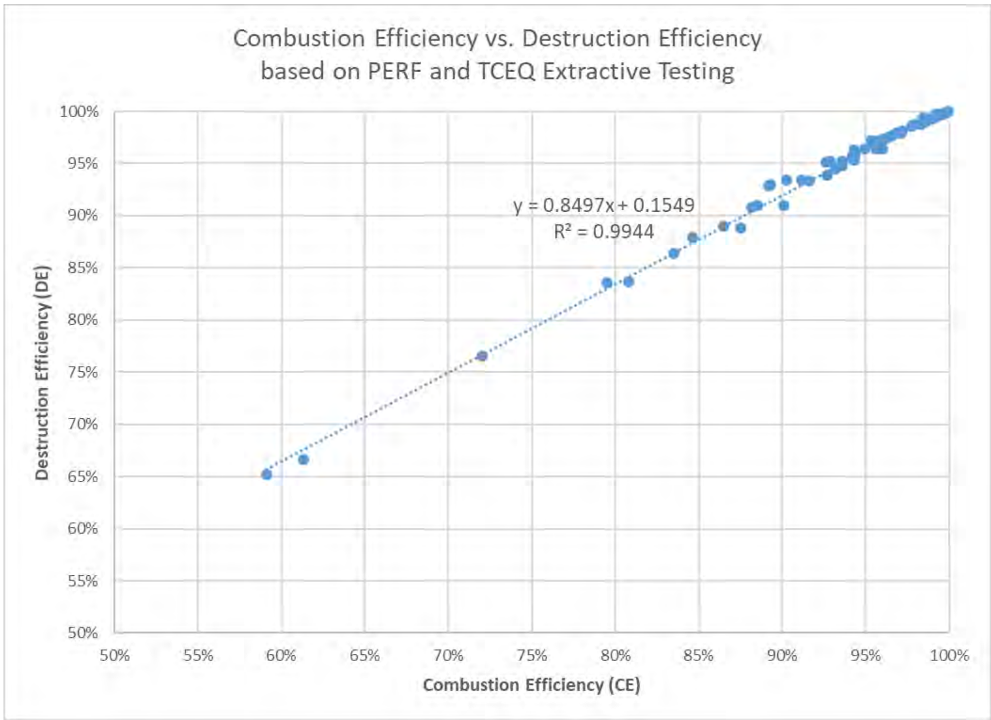

Figure 17. CE vs DE from extractive sampling during PERF and VISR studies.

As demonstrated by the chart, the relationship between DE and CE is quite linear. The fit equation to this data has an R^2 of 0.99. Equation 2 below can be used to convert CE to DE using this correlation:

$$DE\ (\%) = CE\ (\%) * 0.8497 + 0.1549$$

Equation 2

It should be noted that when SI is high and CE appears to be low, the destruction efficiency (DE) may still be high as the hydrocarbons are combusted into soot instead of oxidizing to the ultimate combustion products of water and CO_2. The CE-DE relationship shown in *Figure 8* is established under no smoke conditions. There has not been sufficient study on a similar CE-DE relationship when there is significant smoke in the flare. This equation will be valid for CE within a range of 60% to 99.4%. Above 99.4%, the DE will be capped at 100%. Below 60%, there is no extractive data available to extend the correlation.

PROVIDENCE PHOTONICS

Mantis Performance Report for [redacted] Flare Test

July 2022

Prepared for

[redacted]

[redacted]

[redacted]

PROVIDENCE PHOTONICS PROJECT NO. [redacted]

PREPARED BY
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Introduction

[redacted]) retained Providence Photonics, LLC (Providence) to conduct performance measurements with the Mantis flare monitor. The test was funded in part by the DOE ARPA-E REMEDY program to improve the DRE of flares and reduce methane emissions from flares. The objective of the test was to provide a baseline for [redacted] DreamDuo flare.

The flare test was conducted at the [redacted] [redacted] [redacted] on July 26th, 2022. This report summarizes the performance results recorded by the Mantis flare monitor.

Background

The Mantis utilizes a multi-spectral midwave infrared imager to measure relative concentrations of combustion gases. The method was designed to be a continuous and autonomous remote flare monitor and can be integrated in the plant control system. In this instance, the Mantis data was recorded locally and retrieved later for reporting purposes.

Results

The results from Mantis measurements are tabulated in **Appendix A** and a summary is provided in *Table 1 below*.

Date	Start Time (Local)	End Time (Local)	Test Description	Distance (m)	Temp (°C)	RH (%)	CE Avg (%)	DRE Avg (%)	SI Avg	FF Avg (m2)	FH Avg (MMBTU/HR)	FS Avg (%)
7/26/2022	10:49 AM	10:53 AM	Test Point 2	145	31	45	98.63	99.30	0.7	197.5	6.77	95.9
7/26/2022	11:04 AM	11:07 AM	Test Point 3	145	31	45	98.90	99.51	0.5	170.2	5.21	96.6
7/26/2022	11:16 AM	11:22 AM	Test Point 4	145	31	45	99.05	99.65	0.5	134.2	3.38	96.2
7/26/2022	11:58 AM	12:02 PM	Test Point 4c	145	31	45	99.09	99.69	0.4	94.8	2.05	96.5
7/26/2022	12:55 PM	1:00 PM	Test Point 5	145	32	39	99.14	99.73	0.5	53.6	1.00	97.1
7/26/2022	1:02 PM	1:07 PM	Test Point 6	145	32	39	99.29	99.85	0.5	31.0	0.54	97.2
7/26/2022	1:09 PM	1:15 PM	Test Point 7	145	32	39	99.13	99.72	0.5	26.9	0.44	97.0
7/26/2022	1:17 PM	1:24 PM	Test Point 8	145	32	39	99.20	99.76	0.4	17.6	0.28	97.1
7/26/2022	1:26 PM	1:32 PM	Test Point 9	145	32	39	99.41	99.91	0.3	13.7	0.19	97.1
7/26/2022	1:39 PM	1:45 PM	Test Point 10	145	32	39	99.49	99.94	0.3	10.7	0.14	97.1
7/26/2022	1:48 PM	1:54 PM	Test Point 4d	145	32	39	99.16	99.74	0.4	87.2	1.91	96.5
7/26/2022	2:10 PM	2:15 PM	Test Point 12a	145	32	39	99.54	99.91	0.6	21.7	0.39	94.4
7/26/2022	2:17 PM	2:20 PM	Test Point 12b	145	32	39	99.66	99.93	0.7	21.6	0.43	95.2
7/26/2022	2:26 PM	2:29 PM	Test Point 12b Repeat	145	33	36	99.58	99.96	0.6	21.7	0.44	96.0
7/26/2022	2:36 PM	2:38 PM	Test Point 13	145	33	36	99.51	99.90	1.2	22.4	0.47	95.4
7/26/2022	2:40 PM	2:43 PM	Test Point 14	145	33	36	99.04	99.57	2.6	21.7	0.50	95.2
7/26/2022	2:55 PM	2:59 PM	Test Point 15	145	33	36	99.60	99.94	0.5	22.9	0.40	94.9
7/26/2022	3:01 PM	3:04 PM	Test Point 16	145	33	36	97.61	98.39	0.5	25.0	0.40	91.3
7/26/2022	3:08 PM	3:14 PM	Test Point 17	145	33	36	99.48	99.84	0.4	14.4	0.22	94.8
7/26/2022	3:18 PM	3:22 PM	Test Point 18	145	35	30	98.95	99.55	0.4	9.2	0.13	94.7
7/26/2022	3:29 PM	3:35 PM	Test Point 19	145	35	30	99.12	99.60	2.3	12.7	0.24	94.6
7/26/2022	3:38 PM	3:42 PM	Test Point 20	145	35	30	99.01	99.48	2.9	18.5	0.39	94.7
7/26/2022	3:43 PM	3:48 PM	Test Point 21	145	35	30	98.60	99.16	5.1	16.2	0.38	94.5
7/26/2022	3:56 PM	4:00 PM	Test Point 22	145	35	30	99.45	99.91	0.6	28.7	0.57	95.4

Table 1: Summary Mantis Results.

Flare Performance Metrics

VISR provides five flare performance metrics at a 1-second data interval:

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 2 indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the VISR imager. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the VISR imager in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this test the flame size was above the minimum number of pixels for all measurements performed.

The second important DQI is the Smoke Index level. As the smoke index increases above 2.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Extractive testing shows that SI values above 3.0 may cause a small negative bias on the CE measurement (< 1%) and SI values above 5 may cause a significant negative bias to CE, as confirmed by testing with an extractive sampling method as a control. Any data points with a smoke index above 3 were removed from the summary tables and **Appendix A** results.

Summary

A flare test was conducted at the [redacted] [redacted] [redacted] on July 26th, 2022. The test was funded in part by the DOE ARPA-E REMEDY program to improve the DRE of flares and reduce methane emissions from flares. The objective of the test was to provide a baseline for [redacted] DreamDuo flare. Raw 1-second data and summary data are provided along with this report.

References

1. Yousheng Zeng, Jon Morris & Mark Dombrowski (2015) Validation of a new method for measuring and continuously monitoring the efficiency of industrial flares, Journal of the Air & Waste Management Association, 66:1, 76-86, DOI: 10.1080/10962247.2015.1114045
2. Yousheng Zeng, Jon Morris. (2019, April 2nd). *Precision and Accuracy of the VISR Method for Flare Monitoring*. Air Quality Measurement Methods and Technology, Durham, North Carolina, United States.

Appendix A: Results

Date/Time					Conditions			Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (CST)	End Time (CST)	Test Description	Distance (m)	Temp (°C)	RH (%)	CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	7/26/2022	10:49 AM	10:53 AM	Test Point 2	145	31	45	98.63	99.30	95.46	99.62	0.55	0.7	0.2	2.2	0.3	197.5	9.3	274.3	31.6	6.77	0.11	8.46	1.17	95.9	70.0	100.0	3.4
2	7/26/2022	11:04 AM	11:07 AM	Test Point 3	145	31	45	98.90	99.51	93.16	99.82	0.71	0.5	0.1	1.1	0.2	170.2	107.5	209.1	25.4	5.21	2.85	7.02	1.17	96.6	90.8	100.0	1.9
3	7/26/2022	11:16 AM	11:22 AM	Test Point 4	145	31	45	99.05	99.65	95.68	99.72	0.48	0.5	0.1	3.5	0.3	134.2	22.8	324.5	30.5	3.38	0.28	5.08	0.96	96.2	24.1	100.0	4.7
4	7/26/2022	11:58 AM	12:02 PM	Test Point 4c	145	31	45	99.09	99.69	95.57	99.95	0.30	0.4	0.1	1.4	0.2	94.8	60.4	181.6	16.7	2.05	1.33	3.20	0.43	96.5	68.3	99.8	2.8
5	7/26/2022	12:55 PM	1:00 PM	Test Point 5	145	32	39	99.14	99.73	98.36	99.60	0.15	0.5	0.1	1.6	0.2	53.6	39.4	119.2	6.8	1.00	0.74	1.21	0.09	97.1	56.2	100.0	3.2
6	7/26/2022	1:02 PM	1:07 PM	Test Point 6	145	32	39	99.29	99.85	98.36	99.73	0.19	0.5	0.1	0.9	0.1	31.0	21.2	39.0	3.4	0.54	0.38	0.67	0.05	97.2	91.0	100.0	1.5
7	7/26/2022	1:09 PM	1:15 PM	Test Point 7	145	32	39	99.13	99.72	98.13	99.86	0.30	0.5	0.1	1.4	0.1	26.9	18.0	33.1	3.0	0.44	0.34	0.55	0.04	97.0	79.4	99.8	1.9
8	7/26/2022	1:17 PM	1:24 PM	Test Point 8	145	32	39	99.20	99.76	97.13	99.71	0.33	0.4	0.1	1.1	0.1	17.6	11.5	24.2	2.8	0.28	0.19	0.39	0.04	97.1	67.4	100.0	2.4
9	7/26/2022	1:26 PM	1:32 PM	Test Point 9	145	32	39	99.41	99.91	98.66	99.83	0.21	0.3	0.2	0.6	0.1	13.7	8.8	17.0	1.5	0.19	0.13	0.24	0.02	97.1	92.6	100.0	1.4
10	7/26/2022	1:39 PM	1:45 PM	Test Point 10	145	32	39	99.49	99.94	97.83	99.75	0.29	0.3	0.2	0.5	0.1	10.7	7.9	12.7	1.0	0.14	0.11	0.17	0.01	97.1	92.7	99.9	1.4
11	7/26/2022	1:48 PM	1:54 PM	Test Point 4d	145	32	39	99.16	99.74	98.36	99.83	0.16	0.4	0.2	2.0	0.2	87.2	18.5	155.6	11.5	1.91	0.19	2.31	0.25	96.5	65.0	100.0	2.8
12	7/26/2022	2:10 PM	2:15 PM	Test Point 12a	145	32	39	99.54	99.91	96.69	99.99	0.43	0.6	0.1	1.5	0.2	21.7	5.2	84.1	6.9	0.39	0.06	0.60	0.11	94.4	12.4	99.9	6.9
13	7/26/2022	2:17 PM	2:20 PM	Test Point 12b	145	32	39	99.66	99.93	96.88	99.99	0.43	0.7	0.2	1.8	0.3	21.6	5.2	32.3	6.1	0.43	0.05	0.63	0.15	95.2	50.6	99.9	4.5
14	7/26/2022	2:26 PM	2:29 PM	Test Point 12b Repeat	145	33	36	99.58	99.96	98.86	99.99	0.25	0.6	0.1	1.4	0.2	21.7	17.6	26.0	1.5	0.44	0.33	0.54	0.04	96.0	89.9	100.0	2.0
15	7/26/2022	2:36 PM	2:38 PM	Test Point 13	145	33	36	99.51	99.90	98.46	99.99	0.34	1.2	0.6	2.5	0.4	22.4	17.8	101.6	6.8	0.47	0.36	0.63	0.05	95.4	43.9	99.8	4.8
16	7/26/2022	2:40 PM	2:43 PM	Test Point 14	145	33	36	99.04	99.57	97.13	99.99	0.67	2.6	0.8	4.4	0.8	21.7	13.0	92.9	8.0	0.50	0.34	0.77	0.08	95.2	6.3	99.9	7.0
17	7/26/2022	2:55 PM	2:59 PM	Test Point 15	145	33	36	99.60	99.94	97.54	99.99	0.36	0.5	0.1	1.1	0.2	22.9	17.4	29.2	2.0	0.40	0.32	0.51	0.03	94.9	84.0	99.8	2.6
18	7/26/2022	3:01 PM	3:04 PM	Test Point 16	145	33	36	97.61	98.39	87.41	99.92	2.67	0.5	0.2	1.3	0.1	25.0	4.2	32.4	3.5	0.40	0.01	0.51	0.07	91.3	21.9	99.8	9.4
19	7/26/2022	3:08 PM	3:14 PM	Test Point 17	145	33	36	99.48	99.84	93.56	99.99	0.76	0.4	0.2	0.9	0.1	14.4	7.6	19.4	1.8	0.22	0.10	0.32	0.03	94.8	14.6	100.0	6.7
20	7/26/2022	3:18 PM	3:22 PM	Test Point 18	145	35	30	98.95	99.55	96.33	99.72	0.66	0.4	0.1	0.8	0.1	9.2	6.3	12.1	1.1	0.13	0.09	0.19	0.02	94.7	83.5	99.8	2.7
21	7/26/2022	3:29 PM	3:35 PM	Test Point 19	145	35	30	99.12	99.60	97.37	99.99	0.64	2.3	0.6	4.1	0.7	12.7	8.9	92.8	4.2	0.24	0.14	0.36	0.03	94.6	6.8	99.9	5.6
22	7/26/2022	3:38 PM	3:42 PM	Test Point 20	145	35	30	99.01	99.48	97.16	99.99	0.87	2.9	0.9	6.4	1.1	18.5	12.3	318.5	20.1	0.39	0.28	0.95	0.07	94.7	0.1	99.8	7.4
23	7/26/2022	3:43 PM	3:48 PM	Test Point 21	145	35	30	98.60	99.16	97.53	99.98	1.80	5.1	0.8	7.6	1.8	16.2	6.6	92.8	6.1	0.38	0.13	0.71	0.13	94.5	0.1	99.9	6.2
24	7/26/2022	3:56 PM	4:00 PM	Test Point 22	145	35	30	99.45	99.91	98.42	99.99	0.27	0.6	0.2	1.7	0.2	28.7	19.4	115.5	9.2	0.57	0.37	0.86	0.08	95.4	17.1	100.0	8.3

ANNEX E: Supply Chain Study Results Letter, Submitted September 19, 2023

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

API American Petroleum Institute

AXPC AMERICAN EXPLORATION & PRODUCTION COUNCIL

INGAA Interstate Natural Gas Association of America

IPAA INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

GPA MIDSTREAM ASSOCIATION

jbe ENVIRONMENTAL AND SUSTAINABILITY CONSULTANTS

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

From June through September of 2023, the American Petroleum Institute (API), American Exploration and Production Council (AXPC), Interstate Natural Gas Association of America (INGAA), Independent Petroleum Association of America (IPAA), and GPA Midstream Association (the “Industry Trades”) conducted an operator survey of supply chain delays for components and equipment necessary to comply with the Environmental Protection Agency’s (EPA) proposed rule “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.” To comply with antitrust guidelines the survey was blinded, and data was gathered and complied by a third party consultant, John Beath Environmental.

The EPA’s OOOOb New Source Performance Standard (the “methane rule”) is a complex rule that will apply to many thousands of facilities in producing basins across the country. Because of the wide variety of conditions faced by these facilities, the challenges in acquiring equipment due to ongoing COVID-induced supply chain delays, and additional proposed rules which will apply to these sources such as EPA’s revisions to Subpart W of the Greenhouse Gas Reporting Program (GHGRP) that will also require equipment, **operators need a reasonable timeline based on a December 6, 2022 applicability date to come into compliance with the final methane rule.**

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

Responses to the survey included information from 11 basins; a majority of responses included information from the Permian Basin. The responses suggest that operators have the greatest supply chain concerns with pneumatics, control devices, storage vessels, associated gas, and fugitive emissions components.

The survey found that current backorder times for components range from 6+ to 24+ months. Implementation of the proposed methane rule is expected to increase current backorder times by an additional 6+ months. A November 15, 2021 applicability date is expected to substantially exacerbate the challenges of equipment acquisition over a December 6, 2022 applicability date.

The survey results indicate that reasonable compliance timelines, based on a December 6, 2022 applicability date, would need to allow a minimum of 12 to 26 months for operators to come into compliance with the final methane rule, as appropriate given supply chain backlogs for each affected facility.

Current and Anticipated Supply Chain Delays

- ➢ Current backorder is generally up to 12 months across affected facilities with additional lead time needed for specialized equipment.
- ➢ Finalization of NSPS OOOOb is expected to add a minimum of 6 months of additional backorder time across affected facilities.

Affected Facility	Current Procurement Lead Time ("Backorder") is Delayed	Anticipated Backorder upon NSPS OOOOb Finalization Compared to Existing Lead Time
Pneumatic Controllers and Pumps	• Up to 12 months across equipment options. • Electrical transformers and instrument air skids are experiencing variable delays with 24+ months indicated.	• Add 6 to 12 months
Control Device Provisions	• Up to 12 months for both control devices and other equipment (monitoring, etc.)	• Add 6 to 12 months for control devices and • Add 6+ months for other equipment.
Storage Vessels	• Up to 12 months for steel tanks, vent header control valves • Up to 24 months for VRUs and • Up to 30 months for PVRVs & thief hatches.	• Add 6+ months across equipment
Associated Gas	• Up to 18 months for VRUs, gas compressor skids	• Add 6 to 12 months
Fugitive Emissions Components	• Up to 12 months across monitoring options.	• Add up to 6 months
Other (miscellaneous equipment)	• Up to 18 months for VFDs	• Add 6 to 12 months for VFDs

Recommended OOOOb Compliance Timelines by Affected Facility

Affected Facility / Category	EPA Proposed Compliance Timeline	Anticipated Supply Chain Delay Upon Finalization *(Current lead time + additional anticipated lead time)*	Industry Trades Recommended Compliance Timeline
Pneumatic Controllers & Pumps	60 days	18 - 36 months	26 months
Control Devices and Closed Vent Systems	60 days	18-24 months	20 months
Associated Gas	60 days	30 months	24 months
Fugitive Emissions Components	60 days	18 months	12 months
Storage Vessels	30 - 60 days	18 - 36 months	26 months

API's February 13 comment letter[1] included anecdotal reports of members' supply chain constraints. This survey quantitatively expands on the supply chain issues raised to demonstrate the need for reasonable compliance timelines.

These recommended compliance timelines account only for supply chain delays and do not contemplate the additional time needed to install equipment. The recommendations reflect the realities of the supply chain, balanced with the urgency of aggressive industry action to achieve compliance with OOOOb and reduce emissions.

While this survey evaluated supply chain delays relative to OOOOb compliance and did not contemplate compliance with OOOOc, given the scope of the proposed rules and available data, similar supply chain constraints are anticipated to continue beyond the OOOOc implementation timeframe.

[1] *https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428*

Equipment & Services Included by Affected Facility

- ❑ Survey responses included equipment and services for various compliance options for each affected facility (listed below).
- ❑ The survey included estimated equipment counts, supplier market, and supply chain delays.

Pneumatic Controllers & Pumps

- Electrical Transformers
- Solar Equipment
- Generator Skids
- Instrument Air Skids
- Electrical Valves/Controllers
- Replacement Pumps
- Replacement Controllers
- ECAT System
- Nitrogen Gas

Control Devices & Closed Vent Systems

- Flares
- Enclosed Combustion Devices
- Flow Meters
- Backpressure Valves
- Calorimeters
- Third-party Testing: Performance, Net Heating Value (NHV), Opacity
- Automatic Pilot Light
- Thermocouples
- Piping for Closed Vent System

Storage Vessels

- Steel Tanks
- Pressure-Vacuum Relief Valves (PVRVs) & Thief Hatches
- Vent Header Control Valve
- Vapor Recovery Units (VRUs)*

Associated Gas

- VRUs*
- Methane Pyrolysis Skids
- Gas Compressor Skids
- Gas to Liquids Skids
- Liquefied Natural Gas Production Skids

Fugitive Emissions Components

- Optical Gas Imaging (OGI) Cameras
- OGI Camera Technicians
- Third-party OGI Monitoring
- Third-party Alternative Screening Technology Monitoring
- Continuous Monitoring Systems
- Replacement Piping Components
- Handheld Methane Detectors

Other (Miscellaneous Equipment)

- Variable Frequency Drives (VFDs)
- Cabling (Electric/Communications)
- Engineering Analysis (Associated Gas, Pneumatic Pumps, etc.)
- Eductor Skid (for compressors)

*VRUs were considered separately for Storage Vessels and Associated Gas since size and design may differ.

Estimated Equipment Counts Needed for NSPS OOOOb Compliance

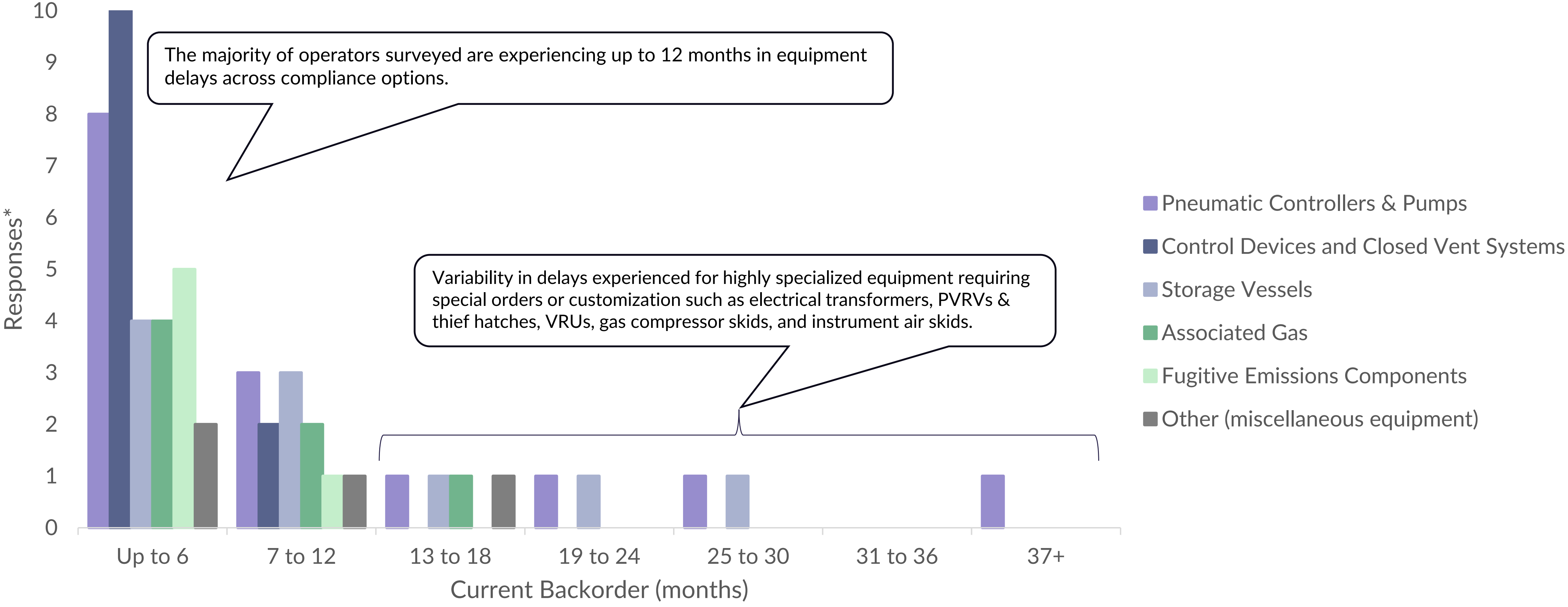
- **Pneumatic Controllers & Pumps**
  - Variety of responses highlight the need for multiple compliance options (i.e., no "one size fits all" solution).
  - 69% of responses indicated that instrument air skids would be needed.
  - Responses continue to indicate that a variety of power generation options will need to be used.
- **Control Devices & Closed Vent Systems**
  - 82% of responses indicated that flow meters would be needed.
  - 27% or more of responses indicated that third-party services (performance testing, NHV testing, or opacity monitoring) were being investigated for use.
- **Storage Vessels**
  - PVRVs & thief hatches were key equipment needed and were not considered in EPA's cost analysis.
  - 29% of responses indicated that steel tanks would be needed, possibly as replacements for fiberglass tanks to facilitate a closed vent system. Replacement tanks were not considered in EPA's cost analysis.
- **Associated Gas**
  - While operators support the concept of other types of beneficial use, responses indicated that operators were not planning to implement alternative technology options proposed by EPA (methane pyrolysis, gas to liquids, liquefied natural gas). The costs of alternative use options were not considered in EPA's cost analysis.
- **Fugitive Emission Components**
  - Responses indicated that most operators were planning to implement their own OGI monitoring program (OGI cameras and technicians). A shortage of OGI technicians was also noted in the responses, and for gas processing operators, availability of qualified OGI camera technicians could be further limited based on the proposed certification and audit requirements in Appendix K. EPA's cost analysis assumed that operators would use a third-party service.

Survey Results Compared to Previous API Comments

- Since the February 13, 2023 comment deadline, equipment backorder has generally remained the same or worsened.
- A reasonable compliance timeline of 12 to 26 months is needed based on a December 6, 2022 applicability date. Additional time would be needed if EPA maintains the November 15, 2021 applicability date.

Supply Chain Item	Survey Results (August 2023)	Previous API Comments (February 2023)	Summary of Comparison
Control Device Backorder	Up to 6 months: 75% 7 to 12 months: 25%	3 to 4 months	Backorder has increased by up to 8 months.
Flow Meter Backorder	Up to 6 months: 83% 7 to 12 months: 17%	6 to 8 months	Backorder remains approximately 6 to 8 months.
Flow Meter Installation Timeline (Hot Tap)	Up to 2 weeks: 50% 3 to 4 weeks: 33% 12+ weeks: 17%	Up to 4 months	Survey results may not reflect hot tap installations.
Instrument Air Skids Backorder	Up to 6 months: 58% 7 to 12 months: 25% 19+ months: 17%	8 to 12 months	Backorder has increased by up to 7 months.
Solar Panels Backorder	Up to 6 months: 80% 7 to 12 months: 20%	18 to 24 months	Backorder has decreased by 6 to 12 months.

Current Procurement Lead Time

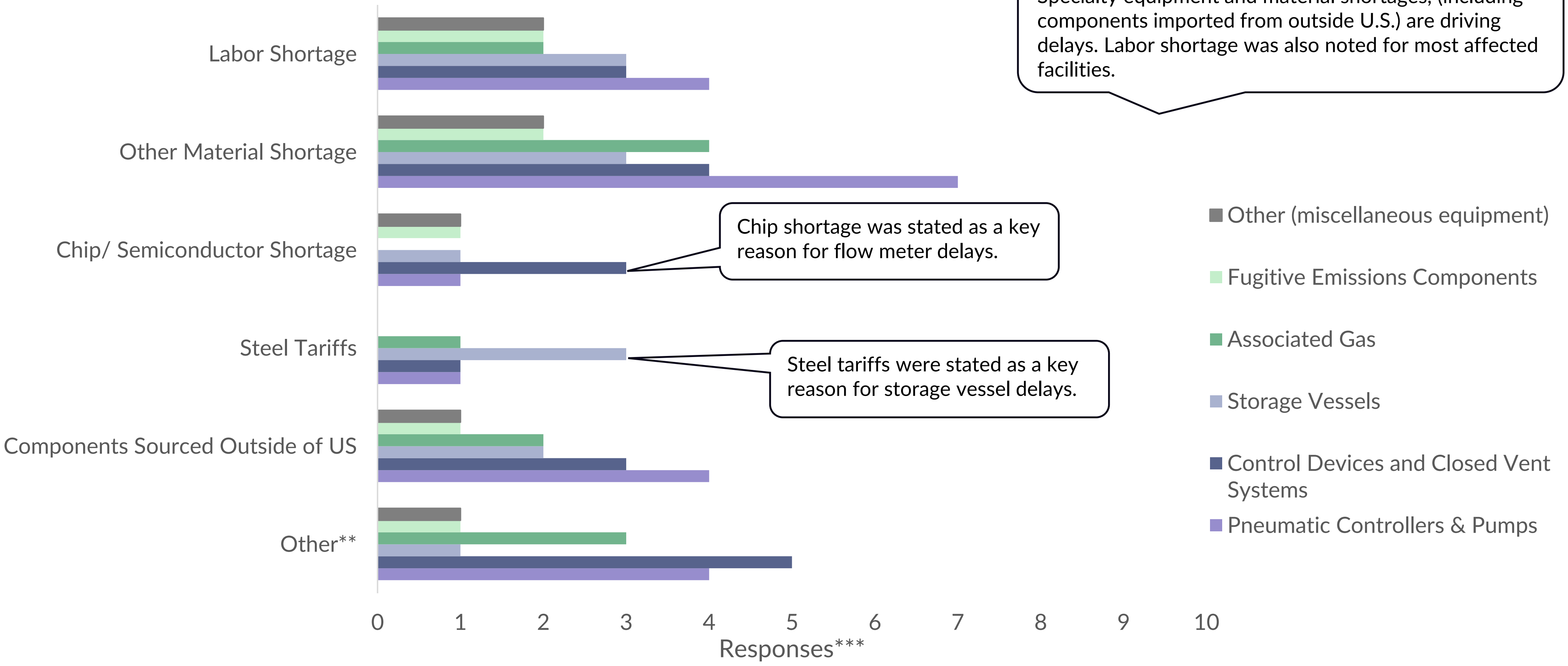


The majority of operators surveyed are experiencing up to 12 months in equipment delays across compliance options.

Variability in delays experienced for highly specialized equipment requiring special orders or customization such as electrical transformers, PVRVs & thief hatches, VRUs, gas compressor skids, and instrument air skids.

*Responses by affected facility based on maximum count for each backorder timeframe.

Supplier-Stated Reason(s) for Backorder*



Specialty equipment and material shortages, (including components imported from outside U.S.) are driving delays. Labor shortage was also noted for most affected facilities.

Chip shortage was stated as a key reason for flow meter delays.

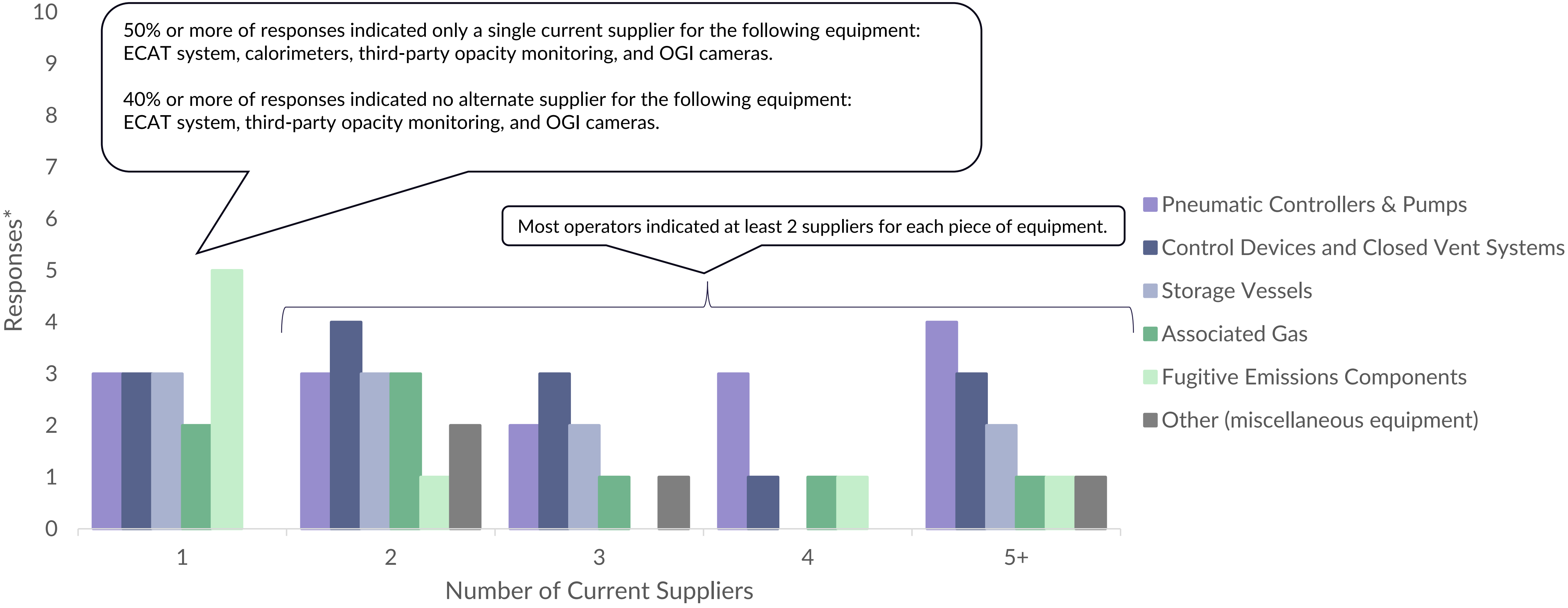
Steel tariffs were stated as a key reason for storage vessel delays.

* Responses could indicate more than one reason for backorder delays

** Other reasons vary by control option but include: “Fabricator backlog”; “Standard lead time”; “Limited inventory as order is customized”; “Engineering design required for proper equipment function”.

*** Responses based on maximum count for each reason.

Supplier Market



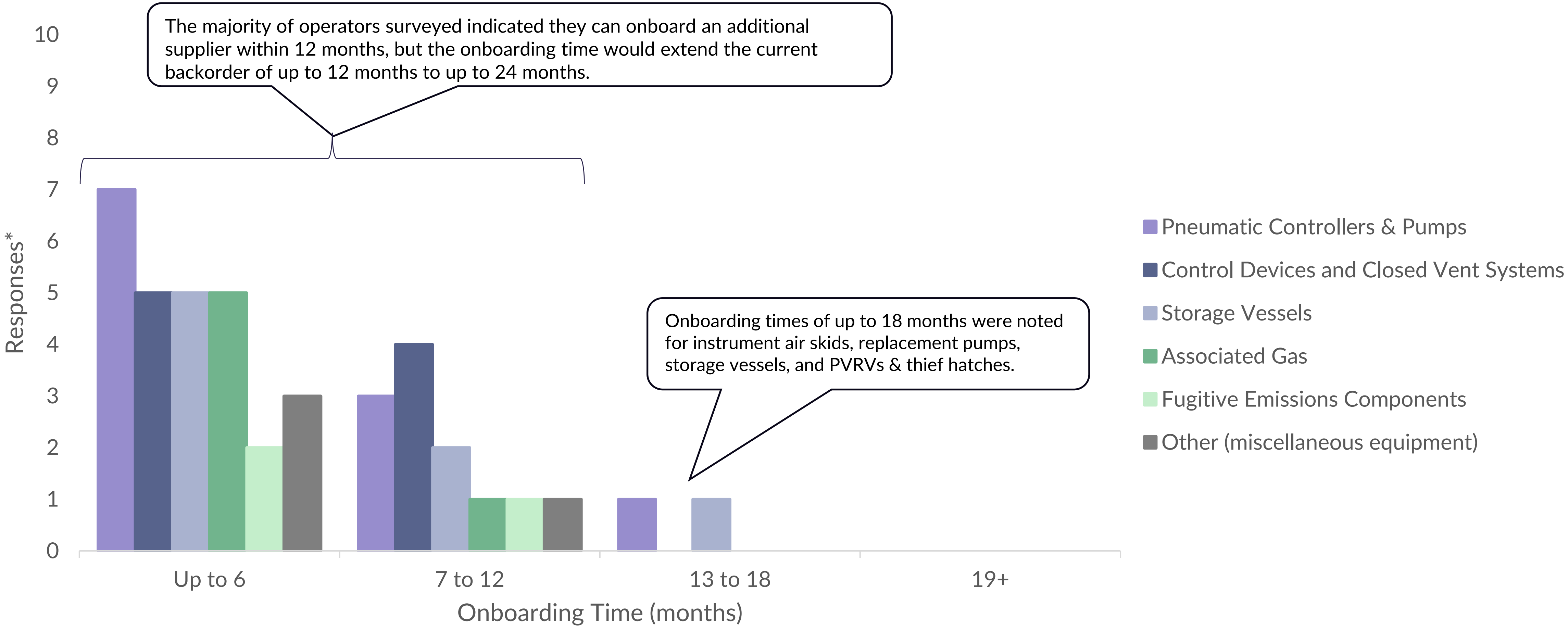
50% or more of responses indicated only a single current supplier for the following equipment: ECAT system, calorimeters, third-party opacity monitoring, and OGI cameras.

40% or more of responses indicated no alternate supplier for the following equipment: ECAT system, third-party opacity monitoring, and OGI cameras.

Most operators indicated at least 2 suppliers for each piece of equipment.

*Responses by affected facility based on maximum count for each number of current suppliers.

Onboarding Time for an Additional Supplier

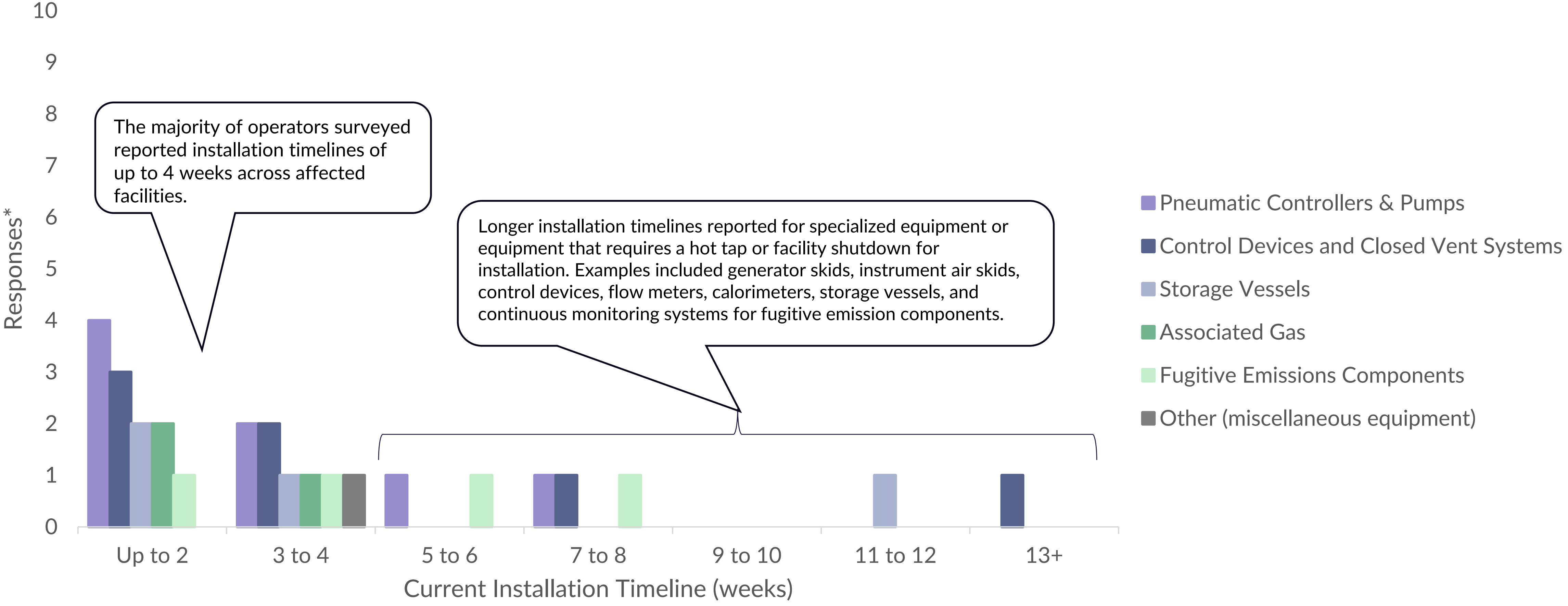


The majority of operators surveyed indicated they can onboard an additional supplier within 12 months, but the onboarding time would extend the current backorder of up to 12 months to up to 24 months.

Onboarding times of up to 18 months were noted for instrument air skids, replacement pumps, storage vessels, and PVRVs & thief hatches.

*Responses by affected facility based on maximum count for each onboarding timeframe.

Current Installation Timelines



The majority of operators surveyed reported installation timelines of up to 4 weeks across affected facilities.

Longer installation timelines reported for specialized equipment or equipment that requires a hot tap or facility shutdown for installation. Examples included generator skids, instrument air skids, control devices, flow meters, calorimeters, storage vessels, and continuous monitoring systems for fugitive emission components.

*Responses by affected facility based on maximum count for each installation timeline.

Reason(s) for Installation Timelines

Labor shortage including specialized labor was the most commonly stated reason for installation delays across affected facilities.

H_2S exposure was noted as a particular safety concern.

* Responses could indicate more than one reason for backorder delays
** Other reasons vary by control option but include: “Engineering evaluation needed”; “Normal construction timeline”; “Weather, road conditions”.
*** Responses based on maximum count for each reason.

ANNEX F: API Assessment of Properly Functioning and Malfunctioning Intermittent Bleed Pneumatic Controllers

Note: Data for this analysis is included separately within this docket in pdf format

ANNEX F

Analysis to Support Amendment to Calculation 3 for Intermittent Bleed Devices Monitoring

EPA should amend Equation W-1C to more accurately reflect available empirical data on emissions from properly functioning pneumatic controllers. This proposed amendment is consistent with data contained in Annex A, the API study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States," and data from the University of Texas,[1] both indicating that malfunctioning intermittent controllers are the primary source of measured emissions; the API pneumatic controller study data indicates it is approximately 85%.

Methods

The UT data[2,3] (304 controllers) and the API data (265 controllers) on natural gas driven intermittent bleed pneumatic controllers were reanalyzed to simulate the use of an IR camera to segregate equipment into malfunctioning and properly functioning controller categories and an average emission calculated for each category after segregation.

Controllers were separated into three groups based on time series behavior, where the detection threshold of the OGI camera was assumed to be 0.9 scfh (~17 g/hr). A sensitivity analysis was conducted to assess the impact of the assumed OGI detection threshold on the results.

Controller categories:[4]

- **Not Malfunctioning**:
    - **Low:** average value of the time series was less than the assumed detection threshold of the camera
    - **Proper:** Either
        - **Return to zero/baseline**: average value was at or above the detection threshold and the last value of the time series was below the threshold, or
        - **Baseline prior to actuation, but measurement terminated during actuation**: average value was at or above the detection threshold and at least half of the data points are less than the threshold.
- Otherwise **Malfunctioning**

The low category represents the equipment that would be viewed as "properly operating" irrespective of time series behavior because emissions would be undetected. The proper category represents equipment that would be viewed as having an actuation associated with emissions, but the actuation would terminate. The "not malfunctioning" category is the combined groups of low and proper. These should be indistinguishable through inspection, since OGI inspection results would be ambiguous as to whether a controller is emitting constantly below the detection limit of the camera or functioning

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[1] http://dept.ceer.utexas.edu/methane/study/datasets3.cfm Data downloaded September 2023.

[2] Ibid.

[3] All pneumatics in UT study were included as intermittent, though there were observations of both low and high continuous bleed devices intermingled. The result of this aggregation increases the properly operating emission factor through the inclusion of low-bleed continuous results that are below the assumed OGI detection threshold.

[4] Files attached dividing those time traces into low, proper, and malfunctioning categories for each the UT and the API data set provides visual inspection to assess implications of these criteria on the time series disaggregation.

properly. The malfunctioning category are the set of observations that are neither categorized as low nor proper. Both studies indicated that malfunctioning intermittent controllers were the majority of measured emissions, including ~85% in the API pneumatic controller study data.[5]

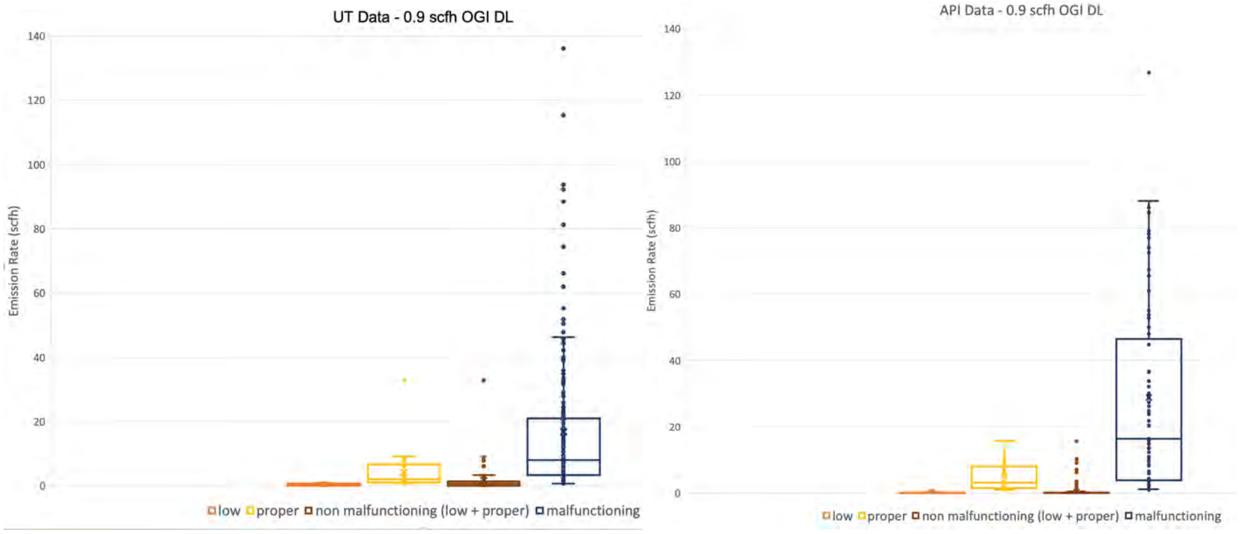
Results

The categorization with OGI camera assumed detection threshold of 0.9 scfh results in a revised set of properly functioning and malfunctioning emission factors of 0.9 and 20.0 scfh, respectively, which would result in a revised equation W-1C as below.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{20.0 \times T_{mal,z} + 0.9 \times (T_{t,z} - T_{mal,z})\} + (0.9 \times Count \times T_{avg})\right] \quad (Rev.Eq.W - 1C)$$

The box and whisker plots in Figure 1 show the low, proper, non-malfunctioning, and the malfunctioning average measurements for the UT, API, and combined UT/API data and Table 1 provides the average and median values from each. As expected, each series is skewed.

Figure 1: Top Left – UT data; Top Right – API Data; Bottom – Combined UT + API data



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[5] API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States."

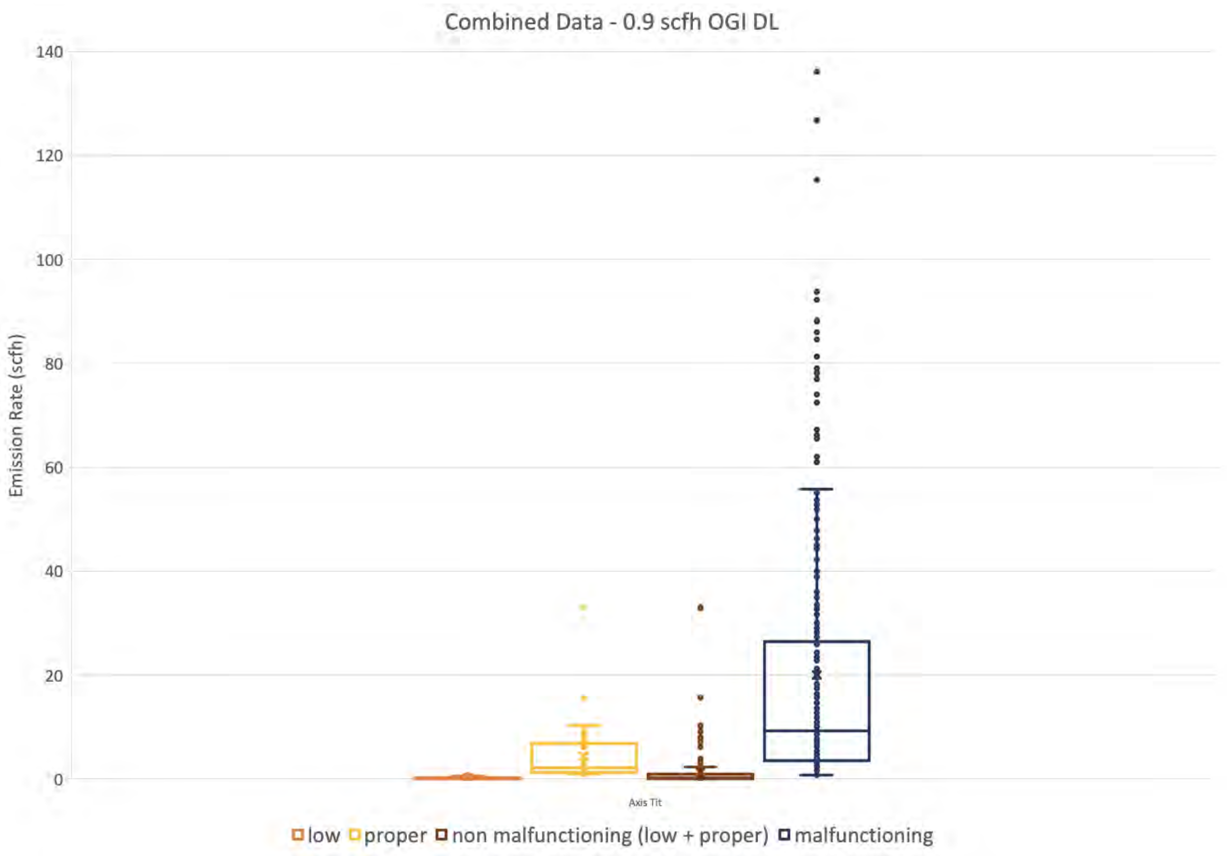

Table 1: Average and median emission rates (scfh) for the low, proper, non-malfunctioning and malfunctioning groups for each the UT, API and combined data sets along with equipment counts in each category.

	Low (scfh) [count]	Proper (scfh) [count]	Non-Malfunctioning (scfh) [count]	Malfunctioning (scfh) [count]
UT – Avg	0.3 [62]	4.3 [36]	1.8 [98]	16.5 [206]
API – Avg	0.1 [171]	5.0 [13]	0.5 [184]	28.8 [81]
Combined – Avg	0.2 [233]	4.4 [49]	**0.9 [282]**	**20.0 [287]**
UT – Median	0.3	2.0	0.7	8.0
API - Median	0.0	2.5	0.0	16.4
Combined - Median	0.0	2.2	0.0	9.3

The non-malfunctioning average emission rate in this segregation of equipment is 0.9 SCFH (68% lower than the proposed factor). The average emission rate of the designated malfunctioning equipment is 20.0 (24% higher than the proposed factor). This results in an overall emission per controller of 10.5 SCFH.

Overall, these results are quite consistent with those from the API pneumatic controller study, insofar as most of the emissions are attributable to the malfunctioning equipment. However, the method of segregating functioning from malfunctioning is different, resulting in a higher properly operating emission factor than the factor proposed in that study analysis shown in Table 2 below. The revised factor of 0.9 SCFH, though larger than the previously proposed factor from the API pneumatic controller study is still significantly lower than the proposed factor in the GHGRP Subpart W proposal.

Table 2: Comparison of the data analyses (former and this work) to proposed emission factors.

	API Study Report Average Emission Rate (SCFH)	API Reanalysis Average Emission Rate (SCFH)	Subpart W Proposed Factors (SCFH)	All data Reanalysis Average Emission Rate (SCFH)
Properly Functioning	0.28	0.5	2.82	**0.9**
Malfunctioning	24.1	28.8	16.1	**20.0**
Average of all equipment	9.25	9.1	-	10.5

One important limitation of the analysis on the UT data is that the time series are much shorter (~2 minutes in duration on average). However, the proposed rule requires an inspection period of 2 minutes.[6]

Sensitivity Analysis

A sensitivity analysis was performed to assess the impact of selecting a theoretical OGI detection limit of 0.6 SCFH. The results are shown in the figure below.

Figure 2: Data categorized as described in methods, with varying assumed detection threshold of OGI from 0.13 scfh to 10 scfh. Dashed lines show the variation of the malfunctioning pneumatic controller average (left axis), solid lines show the variation of the non-malfunctioning (properly operating) pneumatic controller average (left axis), and the dotted lines show the % of controllers that would be classified as malfunctioning under the different detection threshold scenarios (right axis). UT data are shown in orange, API data in blue, and the combined data are shown in black.

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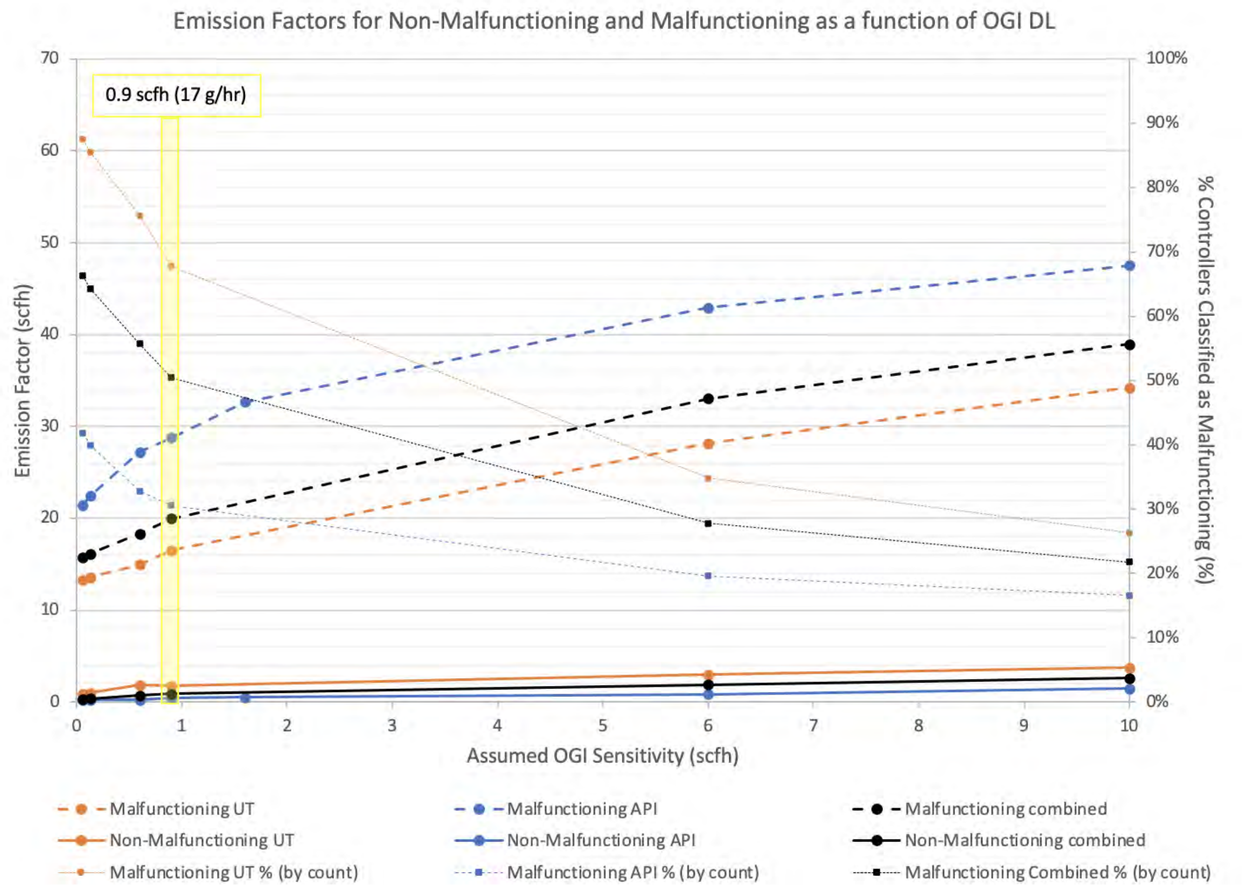
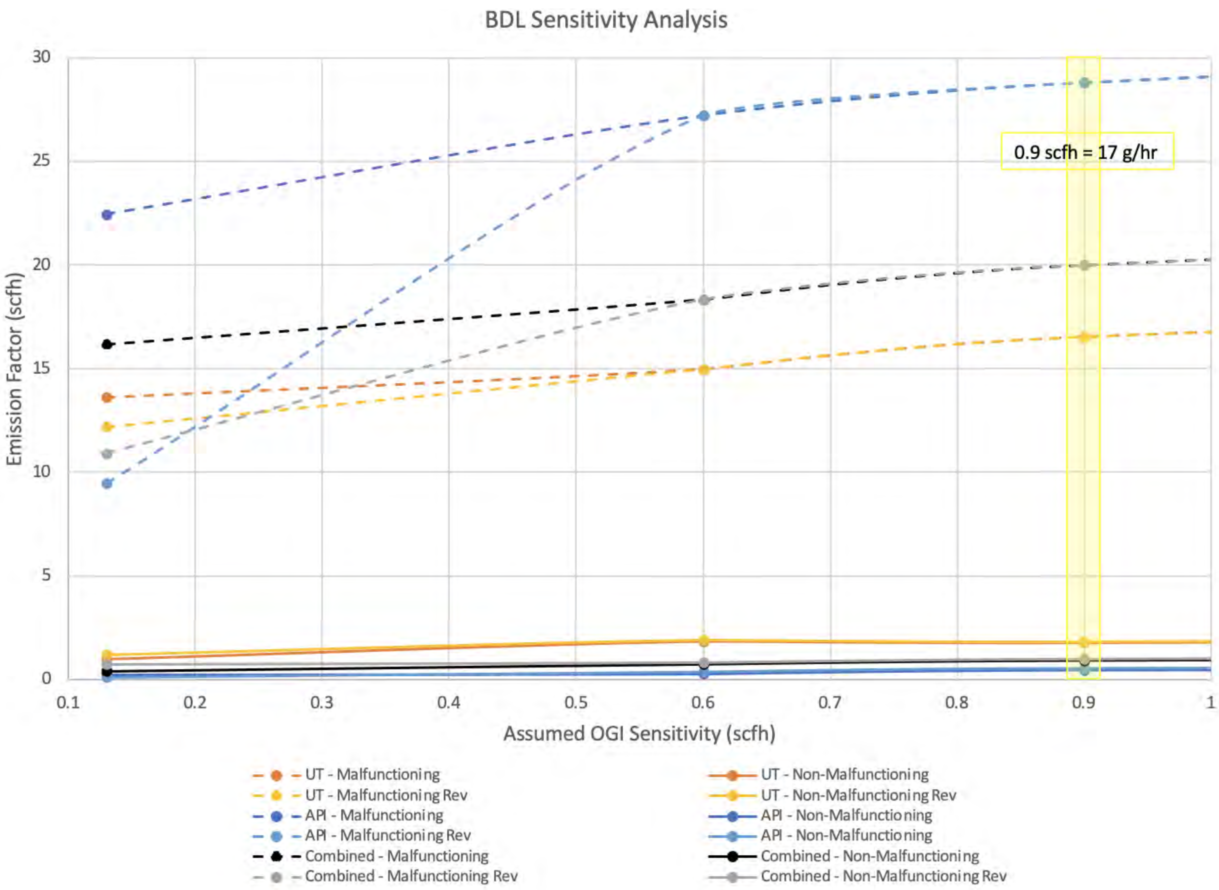
[6] "You must use one of the monitoring methods specified in § 98.234(a)(1) through (3) except that the monitoring dwell time for each device vent must be at least 2 minutes or until a malfunction is identified, whichever is shorter. A device is considered malfunctioning if any leak is observed when the device is not actuating or if a leak is observed for more than 5 seconds during a device actuation. If you cannot tell when a device is actuating, any observed leak from the device indicates a malfunctioning device."



The assumed detection threshold exceeds 10 scfh before the non-malfunctioning (properly operating) average emission reaches 2.82 scfh (proposed factor).

Similarly, a sensitivity analysis was performed to assess the impact of including instrument reported "zeroes" as zeroes. Data substitution was performed to replace all instances of zero with 0.13 scfh to represent the minimum detection limit of the high flowsampler employed in both studies. As shown in Figure 3, there are minor impacts to average emissions for detection thresholds for OGI below ~0.6 scfh, but there is no impact on the proposed range of emission factors.

Figure 3: Data categorized as described in methods, with varying assumed detection threshold of OGI from 0.13 scfh to 1 scfh under two scenarios: 1) data are used as reported and 2) zeroes are substituted with the instrument MDL of 0.13 scfh. Dashed lines show the variation of the malfunctioning pneumatic controller average (left axis) and solid lines show the variation of the non-malfunctioning (properly operating) pneumatic controller average (left axis). UT data are shown in dark orange with the revised data in light orange, API data in dark blue with the revised data in light blue, and the combined data are shown in black with the revised data shown in grey.


BDL Sensitivity Analysis
Emission Factor (scfh)
30
25
20
15
10
5
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Assumed OGI Sensitivity (scfh)
0.9 scfh = 17 g/hr
UT - Malfunctioning
UT - Malfunctioning Rev
API - Malfunctioning
API - Malfunctioning Rev
Combined - Malfunctioning
Combined - Malfunctioning Rev
UT - Non-Malfunctioning
UT - Non-Malfunctioning Rev
API - Non-Malfunctioning
API - Non-Malfunctioning
Combined - Non-Malfunctioning
Combined - Non-Malfunctioning Rev

AXPC | AMERICAN EXPLORATION & PRODUCTION COUNCIL

March 26, 2024

U.S. Environmental Protection Agency
EPA Docket Center, Air and Radiation Docket
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

Subject: **Waste Emissions Charge for Petroleum and Natural Gas Systems**
Docket ID No. EPA–HQ–OAR–2023–0434

Dear Madam or Sir:

The American Exploration and Production Council (AXPC) appreciates the opportunity to provide input responsive to the Environmental Protection Agency's (EPA) Proposed Rule "Waste Emissions Charge for Petroleum and Natural Gas Systems" (89 FR 5318, January 26, 2024) ("WEC").

AXPC is a national trade association representing 34 leading independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate.

As part of this mission, AXPC members understand the importance of ensuring positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. The United States is a world leader in oil and natural gas production, achieving that status while at the same time substantially reducing emissions. The historic reductions in US greenhouse gas (GHG) emissions over the last decade have been driven by the emergence of US natural gas production as a low-cost source of reliable energy. It is important that regulatory policy enables us to build on that success.

AXPC companies are focused on reducing methane emissions from their operations and support effective and reasonable regulation of methane that balances the essential value of US oil and natural gas production with the global challenge of addressing climate change. AXPC companies believe collaboration amongst policy makers and industry partners is needed to find solutions that will meaningfully drive down emissions, while allowing US independent producers to meet the global demand for affordable and reliable oil and natural gas. It is in the spirit of this aim that we offer these comments to EPA proposed rule.

As established in the Inflation Reduction Act (IRA), the implementation of the WEC should be done in a manner that is equitable to operators of varying sizes and portfolios. AXPC is concerned that EPA's proposal offers a simplified calculation of methane intensity that does not take into account the products that the upstream *oil* and gas industry produces and in doing so unduly punishes operators who produce large amounts of energy in the form of oil or NGLs over other production profiles. In our detailed comments attached, we recommend that EPA amend the Facility Methane Intensity calculation to define the numerator as waste emissions relative to the amount of *natural gas sold*. In other words, defining WEC Facility Methane Emissions, as the portion of the emissions attributable to the natural gas sent to sales or facility throughput. Such an approach conforms to the plain reading of the statute and congressional intent; and it is consistent with life cycle assessment practices, and would help avoid unintended negative outcomes that might otherwise result from the inequitable program proposed.

Additionally, in order to stay true to Congress's directive, it is critical that EPA develop an approach to the Regulatory Compliance Exemption that ensures its availability and utility as Congress clearly intended. Under the terms of the proposal, the Regulatory Compliance Exemption would not be available for at least three years, and once available, will be virtually impossible to achieve. If EPA were to finalize such an approach, it would amount to giving no meaningful effect to Congress's intent to provide a Regulatory Compliance Exemption, standing in conflict with established legal precedent for such matters.

Finally, AXPC requests clarification from EPA on the netting provisions of "WEC applicable facilities." As explained further in AXPC's detailed comments, as currently proposed, the inability to net assets that have achieved regulatory compliance or whose emissions are below the WEC threshold may not incentivize deeper emission reductions. Similarly, inability to net assets at the parent company level may also hold back the incentives for operators to make the most impactful emission reductions in their portfolio of assets. We believe these outcomes to be contrary to both EPA and Congress's intent for this program.

With these priority topics in mind, we respectfully submit the below detailed comments on the (EPA's Proposed Rule to implement the "Waste Emissions Charge for Petroleum and Natural Gas Systems." We have identified a number of issues of significant concern and other minor items for which we request additional clarity in the regulatory text consistent with our understanding of EPA's stated intention in the preamble and where appropriate offer potential recommended solutions.

Please do not hesitate to contact me, Wendy Kirchoff (281-386-7324), or Rebecca Denney (972-989-3912), if you have questions or need additional information on any of these items. We look forward to continued collaboration.

Sincerely,

Wendy Kirchoff

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Detailed Comments on

Environmental Protection Agency's (EPA's)
"Waste Emissions Charge for Petroleum and Natural Gas Systems"
at 89 Fed. Reg. 5318 (January 26, 2024)

Docket ID No. EPA–HQ–OAR–2023–0434

March 26, 2024

I. EPA should amend the Facility Methane Emissions calculation to define the WEC Facility Methane Emissions as the portion of the emissions attributable to the natural gas sent to sales or facility throughput.

Clean Air Act (CAA) section 136(c) instructs the Administrator to "impose and collect a charge *on methane emissions that exceed an applicable waste emissions threshold* [emphasis added] under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to Subpart W of part 98 of title 40, Code of Federal Regulations, regardless of the reporting threshold under that subpart." Subsection (f) defines such a threshold as a "charge on the *reported metric tons of methane emissions from such facility that exceed (A) 0.20 percent of the natural gas sent to sale from such facility; or (B) 10 metric tons of methane per million barrels of oil sent to sale from such facility* [emphasis added], if such facility sent no natural gas to sale" or, similarly for nonproduction petroleum and natural gas systems, a "*charge on the reported metric tons of methane emissions that exceed 0.05 percent of the natural gas sent to sale from or through such facility* [emphasis added]."

A plain reading of CAA sections 136(c) and (f) clearly indicates that the methane emissions subject to evaluation against the Waste Emission Threshold for a given segment are those emissions attributable to the specifically listed product (e.g., natural gas sent to sale from a natural gas production facility, oil from an oil producing facility, natural gas sent to sale through a nonproduction petroleum and natural gas system). But EPA went beyond the statutory text, fundamentally changing its meaning with its addition of the word "all" when it proposed "to interpret 'reported metric tons of methane emissions' to mean *all reported methane emissions from a facility*, as reported under Subpart W." 89 Fed. Reg. at 5327/2 (emphasis added).

This is not an appropriate implementation of the statutory text. Rather, the WEC Facility Methane Emissions should be those reported pursuant to Subpart W that are attributable to the relevant product in the segment Waste Emissions Threshold. This is the correct way to give force to all provisions of Section 136 because read together: Subsection (c) directs EPA to "impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f)," and subsection (f) in turn tells EPA what to do when "to imposing and collecting the charge under subsection (c)." EPA should "impose and collect the charge on the reported metric tons of methane emissions from such facility that exceed—

a) 0.20 percent of the natural gas sent to sale from such facility; or
b) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale."

EPA does not identify its authority to impose and collect a charge on emissions other than those specifically referenced in (f)(A) and (B), nor does the text of Section 136 provide any.

Therefore, wherever there is natural gas sent to sale from the facility, the quantity of methane emissions in the numerator should reflect the total methane emissions attributable to the quantity of natural gas sent for sale represented in the denominator. This is managed in the commonly adopted

Natural Gas Sustainability Initiative (NGSI) protocol[1] on an energy allocation basis by multiplying the methane emissions by a gas ratio, which is defined as the energy content of the produced gas divided by the energy content of total produced hydrocarbons (values already reported through Subpart W filings) as shown below in equation 1.

$$Intensity\ IRA = \frac{CH_4\ emissions * Gas\ ratio}{sales\ natural\ gas}, \text{ where} \tag{1}$$

Gas ratio = energy content of produced gas / energy content of total hydrocarbons

Such an approach conforms to the plain reading of the statute and is consistent with practices in the life cycle assessment (LCA) community as illustrated in the implementation of the California Low Carbon Fuel Standard (LCFS)[2] or renewable fuel standard for transportation fuels.

Allen et al.[3] illustrated the importance of including emissions allocation on an energy basis, even within a single basin. In that work, the Eagle Ford Shale is analyzed across 12 subregions, ranging from primarily oil production to primarily dry gas production. When energy allocation is considered, similar methane intensities are observed across all subregions, but when all emissions are attributed solely to the natural gas portion of production (as is inherent in a metric lacking product allocation), the oil producing regions were significantly disadvantaged by as much as an order of magnitude with an unallocated methane intensity metric. This is because without energy allocation, the assessment is inherently biased: the methane associated with the total fluids production is included in the numerator (methane associated with oil AND gas production) but only the gas portion of the total sold is used in the denominator.

This bias is illustrated in Figure 1 below, where assets reported into the GHGRP for reporting year 2022 are plotted on a methane per energy intensity basis, as a function of production energy. Each dot in the figure represents a single reported facility (production and gathering and boosting facilities have been aggregated to single facilities when reported separately by the same reporting entity within a single region). Where methane emissions exceed the WEC threshold (0.2% of reported gas to sales for production and 0.05% of gas throughput for boosting and gathering), the dot is colored blue. Where methane emissions are less than the WEC threshold, the dot is colored green. The WEC threshold for production is overlaid as a red line, where 0.2% of a purely gas producing asset corresponds to 38.4 MT methane/btu.

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[1] https://www.eei.org/issues-and-policy/NGSI

[2] California Air Resources Board. California Low Carbon Fuel Standard. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard

[3] Allen, David T.; Chen, Qining; Dunn, Jennifer B. "Consistent Metrics Needed for Quantifying Methane Emissions from Upstream Oil and Gas Operations." Environ. Sci. Technol. Lett., 2021, 8, 4, 345-349.

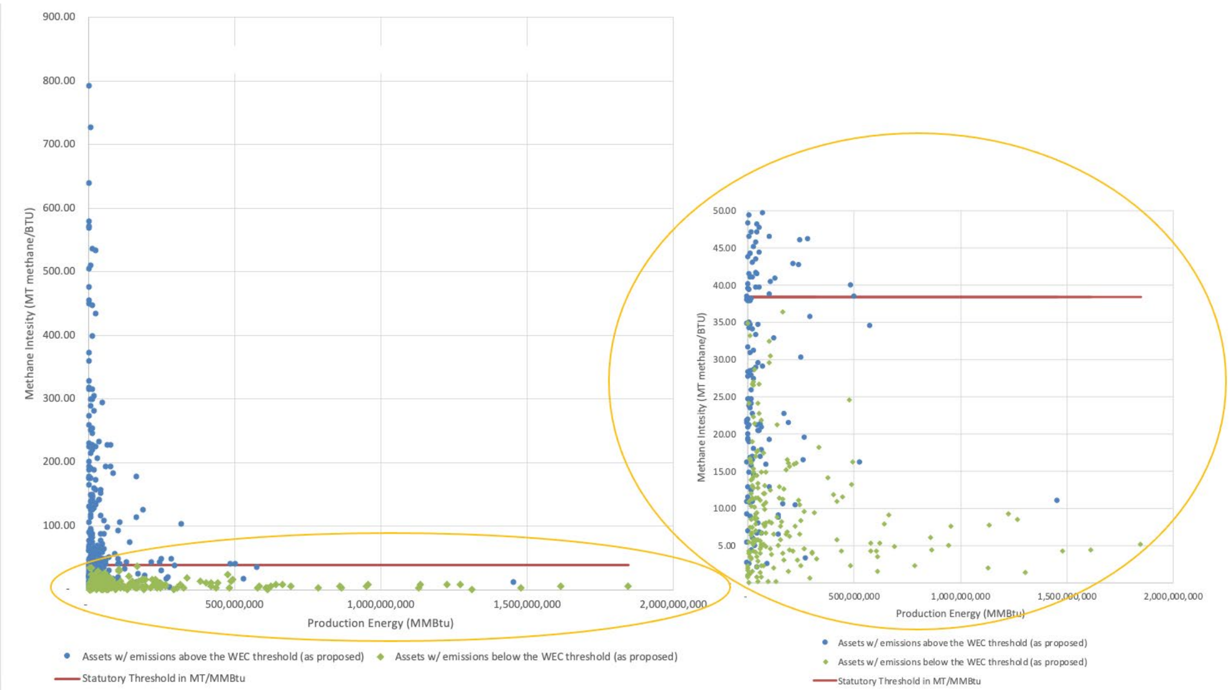

Figure 1 – *Emissions intensity as a function of production energy for the 2022 reporting year pursuant to Subpart W disaggregated by assets below and above the WEC threshold calculated as proposed, attributing all Subpart W emissions to gas only (except where no gas is sent to sale).*

In all cases, assets with high methane intensity on an energy basis exceed the WEC threshold. Most instances of low methane intensity on an energy basis fall below the WEC threshold. There are a handful of cases where assets with *low* methane intensity on an energy basis *exceed* the WEC threshold. In all of these cases, the operator largely produces energy in the form of oil and/or NGLs. In fact, as Table 1 shows, the average percent of energy sold derived from gas for the subset of assets that are low methane intensity on an energy basis but also above the asset WEC threshold is 30% compared to 67% of energy sold derived from gas for all assets and 73% for the assets that are low methane intensity and below the WEC threshold.

Intensity	**WEC Threshold**	**% of Energy Produced as Natural Gas**
Low[1]	Under	73%
Low[1]	Above	30%
All	All	67%

Notes:

1. *Low is considered to be less than 38.4 MT methane/btu which is equal to 0.2% when converted.*
2. *All data sourced from EPA Facility Level GHG Emission Data*

Table 1: *Analysis of intensities, the WEC threshold, and energy production from natural gas.*

Additionally, the language of CAA Section 136 focuses on minimizing waste. *See* Sec. 136(a)(3)(B), (C) (providing funding for "improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions *and waste*; ... supporting innovation in reducing methane and other greenhouse gas emissions *and waste* from petroleum and natural gas systems") (emphases added); 136(c) (titling the program that the proposal implements the "Waste emissions charge"); 136(f) ("Waste emissions threshold"); 136(h) (directing EPA to revise Subpart W to ensure that reports thereunder "accurately reflect the total methane emissions *and waste emissions* from the applicable facilities") (emphasis added).

This last passage is an especially strong signal that EPA, as explained above, is not to impose and collect WEC charges on *all* methane emissions, but rather on the *waste* emissions that exceed the waste emissions threshold for the specific segments identified in Subsection (f), since this last passage reveals that Congress identifies "waste emissions" (on which the "Waste Emissions Charge" is to be imposed and collected) as a discrete subset of "total methane emissions."

If an operator were required to apply a purely natural-gas-based waste emissions threshold to all emissions associated with a liquids production facility, that operator would be perversely incentivized to waste (not sell) any associated gas, likely via flaring, simply to avoid the waste emissions charge from methane emissions incorrectly associated with a comparatively small volume of "gas sent to sales".

Moreover, the assignment of all methane emissions to the natural gas portion of production and processing suggests that US oil and natural gas liquids (NGLs) have a methane intensity of zero. In fact, there are facilities that emit methane and are exclusively dedicated to liquids production or processing. Congress clearly understood this and designated a specific waste emissions threshold for production facilities with no marketed natural gas. Another scenario was identified in EPA's preamble discussing gathering and boosting and processing facilities with zero reported throughput of gas. EPA correctly identified that there are a small number of gathering and boosting and natural gas processing facilities that emit methane and report under Subpart W, but do not send gas to sales. Under the current proposed implementation of the statute, these facilities, which in general exclusively, or almost exclusively, handle NGLs or oil, with no reported throughput of natural gas to sales, are incorrectly considered in excess of the waste emissions threshold for any and all reported emissions.

Applying an energy allocation basis would resolve this issue by allocating emissions based on energy of products received by the facility, where these volumes are already reported to the GHGRP through Subpart W.

EPA indicates it is aware of other approaches for calculating "methane intensity" using energy allocation methods, but suggests that its proposal is more practical since the proposed approach "can be implemented with data currently reported under Subpart W" and other methods would increase operator burden. Setting aside the aforementioned disproportionate financial burden looming over operators producing or handling liquids rich assets relative to those producing or handling principally dry gas under the current proposal, the necessary information to apply an energy allocation to the facility emissions tabulation are also already currently reported under Subpart W.

Data reported under Subpart W for production facilities include:

- Quantity of gas produced in the calendar year from wells (thousand standard cubic feet) [98.236(aa)(1)(i)(A)]
- Quantity of gas produced in the calendar year for sales (thousand standard cubic feet) [98.236(aa)(1)(i)(B)]

- Quantity of crude oil and condensate produced in the calendar year for sales (barrels) [98.236(aa)(1)(i)(C)]

Data reported under Subpart W for boosting and gathering facilities include:

- Quantity of gas received by the gathering and boosting facility in the calendar year (thousand standard cubic feet) [98.236(aa)(10)(i)]
- Quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year (thousand standard cubic feet) [98.236(aa)(10)(ii)]
- Quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year (barrels) [98.236(aa)(10)(iii)]
- Quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year (barrels) [98.236(aa)(10)(iv)]

EPA says that operators would need to collect and report additional detailed information on all of the constituents of the natural gas and other hydrocarbons in order to apply an energy allocation approach. However, just as EPA proposed to consistently apply the density of methane to the natural gas quantity irrespective of small variations in sales gas composition, EPA could also include standard, representative energy conversion factors to apply to the reported quantities of gas and liquid products. Such an approach would allow uniform, representative allocation of emissions by product using widely accepted standard values. AXPC recommends energy conversion factors of 5.7 million BTU (MMBtu)/barrel for liquids and 1.0 million BTU (MMBtu)/thousand SCF (Mcf) of gas.[4]

II. EPA should clarify that a parent company may function as a common WEC obligated party for the WEC applicable facilities of its subsidiaries and may choose to include facilities that fall under the 25,000 tons CO_2e applicability threshold.

EPA proposes that netting may occur only across entities that have the same owner or operator. However, in many of the segments (for example, onshore and gathering and boosting), the term ‘operator’ is very specifically defined and reflects one, very specific operator. Often this is an entity that is established for operation in a particular region or in a particular industry segment. Thus, many times, the name of the entity operating the onshore production assets will be different (although under the same parent and company umbrella) as the entity operating gathering and boosting assets. In other cases, an entity operating the onshore production assets in one basin will be different than the operator of onshore production assets in another basin. Thus, limiting netting to the same operator will likely have the effect of significantly reducing or eliminating the ability for operators to use the intended netting provision.

Additionally, companies often retain the name of a legacy operating company even after acquiring assets, even though the new “parent company” ultimately makes capital allocation decisions, consolidates for tax purposes, etc. – leaving the subsidiary to manage daily operations. In some cases,

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[4] https://www.eia.gov/energyexplained/units-and-calculators/ with cited source Data source: *Monthly Energy Review*, May 2023; preliminary data. Prices are nominal prices (not adjusted for changes in the value of the U.S. dollar). https://www.eia.gov/totalenergy/data/monthly/pdf/sec12_3.pdf

there may be a corporate structure that acquires a company or asset to be a wholly or partially owned subsidiary. In these instances, there may be multiple operators of WEC applicability facilities that are owned by the same parent company – the company that ultimately has control over operations of the WEC applicable facility. A company should be able to net across assets over which it has control of the operations. Precluding such netting across assets provides no incentive for companies to find reductions anywhere they can in order to reduce overall methane emissions. For example, certain operations, areas, or regions may have better access to electricity. Assets in those areas or regions are better positioned to reduce methane emissions through electrification. Operators should be encouraged to find those reductions in areas where they can, even in areas where the WEC applicable facility is already below the WEC threshold. Allowing netting across subsidiaries within parent companies will allow for this. Similarly, where operators have both onshore and gathering and boosting operations, the ability to net where owned by the same parent can encourage creative and thoughtful planning and design to reduce emissions along the natural gas value chain where most available and in places that can achieve the greatest reductions. Restricting netting is inadvertently setting a "floor" for emissions reduction by disincentivizing reduction below the legislatively established thresholds established in the IRA which was not the intent of Congress.

This is consistent with EPA's goal of aligning reporting requirements under Subpart W, both in terms of timing and responsibility. AXPC's proposal would maintain a reporting structure where facilities, as reported under Subpart W, remain intact as WEC obligated facilities. And each reported facility should have an individual owner or operator responsible for reporting and filing the WEC. However, such entities should be able to net with any sister companies. Circumstances described above, such as discrepancies in naming conventions or for a legacy corporate name that may persist in Subpart W designated representative representations, should not limit aggregation of WEC applicable facilities into a single WEC filing by a single WEC obligated party. Furthermore, to the extent that a company voluntarily reports facilities that fall under the 25,000 tons CO_2e applicability threshold, those facilities should also be included as a WEC applicable facility. AXPC recommends that EPA clarify that a parent company may function as the WEC obligated party for the WEC applicable facilities of its subsidiaries.

III. EPA's proposed reporting deadlines associated with the WEC are unreasonable and should be revised in two important ways: 1) The WEC filing and payment deadline should be 30 days after EPA concludes its Subpart W data verification activities or November 1 of each year, whichever comes later, and 2) the proposed deadline to disallow part 99 resubmissions after November 1 of the year following the reporting year should apply to EPA requests for revisions in addition to operators' voluntary resubmission.

Under 40 CFR 98 Subpart W, GHG emissions and data are due to the EPA on March 31 of the following year. Historically, EPA continues to review and require changes to Subpart W submissions months and even years after the submittal deadline. In this regard, we note that Congress has not given EPA direction with respect to when it should require obligated parties to submit their WEC payments. Subsection 136(g) provides only that "[t]he charge under subsection (c) shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter." In stark contrast, subsection (h) *does* provide a date certain by which EPA is to finalize its revisions to Subpart W. This contrast shows that Congress wished EPA to have timing flexibility on when WEC charges are to be imposed and collected.

But EPA's proposed rule does not acknowledge Congress's silence in this respect, nor does it give any explanation for proposing to align WEC payment dates with Subpart W filing dates, *see* 89 Fed. Reg. at 5350. Requiring companies to submit the WEC filing and remit applicable WEC obligation on the same day will result in numerous instances of refiling and confusion - particularly as implementation of revised Subpart W requirements and provisions occurs.

Companies should submit their WEC filings and EPA should complete any verifications and/or audits before companies are required to submit their WEC obligation payments. EPA has stated that companies must submit any revisions to their WEC filings by November 1st of the year after the reporting year (i.e., approximately 7 months after the WEC filing). EPA has indicated that changes to the WEC filings (with limited exceptions for submitting exemption report information) cannot be made by the operator after that date. If this deadline is imposed on operators as a deadline after which revisions may not occur, that same deadline should apply to EPA. Thus, if EPA does not request corrections before November 1, the GHG reported emissions are final.[5]

EPA in its final rule should provide that WEC obligation payments are due within 30 days of that November 1st date. This approach will avoid creating unnecessary burden on both the agency and reporters to track, modify, and in some cases reimburse payments in response to EPA or an operator's identified need for revisions to a submitted report, as commonly occurs in the program including for many accepted and compliant reasons. This staggered WEC filing and WEC obligation timeline (with a half year to complete any revisions – whether by EPA or the operator) will also eliminate potential complications with the three types of financial sanctions (i.e., two different potential interest payments and administrative penalties) that could result from a timely but inaccurate WEC obligation payment at the time of the WEC filing. While AXPC understands EPA's desire to incentivize accurate reporting, the reports that are required under Subpart W and form the basis of the WEC filing are among the most extensive in the country. These could require – for a particular WEC applicable facility – thousands to tens of thousands of calculations. AXPC is aware of no other reporting scheme with that level of detail. Operators work diligently to file accurate statements, but there is an inherent risk of minimal and generally inconsequential mistakes based upon the shear extent and scope of reporting. Such dynamics are often further complicated by other dynamics such as mergers and acquisitions of companies and/or assets. Penalties should not be assessed due to good faith but erroneous efforts. Delaying the obligation to pay the WEC fee until after WEC filings are deemed complete and finalized will eliminate such outcomes and avoid the needless confusion and dedication of resources from agency and operator alike that will otherwise incur should the timing of WEC obligations be finalized as proposed.

IV. EPA should allow operators to provide empirical data as part of the WEC filing, consistent with Congressional intent.

AXPC urges EPA to allow operators, upon their election, to utilize a mechanism by which to provide empirical data as part of the WEC filing that demonstrates that an emission factor or factor for a particular piece of equipment overestimates emissions and that empirical data appropriately reflects a

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[5] AXPC believes that any audits should be completed by this November 1st date. If EPA does not adopt the proposal to complete audits by November 1st, there must be a date certain by which EPA can no longer conduct an audit, EPA must have a basis to believe there are significant errors before requiring an audit, and EPA should not impose any penalties for revised WEC obligations or should provide opportunities and bases for waiving any penalties.

lower waste emission charge obligation. Providing such an opportunity is consistent with Congress's directive to EPA to update Subpart W to reflect empirical data.

V. EPA should develop an approach that ensures the availability and utility of the intended exemption for regulatory compliance

Under the Inflation Reduction Act (IRA), Congress exhibited a clear intent to require that EPA provide an exemption from the WEC for applicable facilities that are subject to and in compliance with certain CAA 111(b) and (d) regulations (herein the "Regulatory Compliance Exemption"). Specifically, Congress provided that:

> Charges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 7411 of this title upon a determination by the Administrator that—
>
> > (i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 7411 of this title have been approved and are in effect in all States with respect to the applicable facilities; and
> >
> > (ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 Fed. Reg. 63110 (November 15, 2021)), if such rule had been finalized and implemented.
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> 42 U.S.C. § 7436(f)(6).

Congress could not have intended for the exemption to be essentially unattainable. However, as proposed, EPA's implementing rule will eviscerate the Regulatory Compliance Exemption. Under the terms of the proposal, the Regulatory Compliance Exemption would not be available for *at least* three years (because, in the final methane rule, this is how long EPA has allowed for states to submit their 111(d) plans and for EPA to review and approve or disapprove them) and once available, will be virtually impossible to achieve (particularly for the onshore and gathering and boosting sectors) – thus, giving no meaningful effect to Congress's intent to provide a Regulatory Compliance Exemption. In other words, EPA has effectively interpreted the Regulatory Compliance Exemption out of the statute. *Zadvydas v. Davis*, 533 U.S. 678, 696 (2001) (if Congress made its intent clear in the statute, courts "must give effect to that intent"); *cf. Kosak v. United States*, 465 U.S. 848, 854 (1984) (a court should not interpret a statute to "nullif[y]" a portion of the statute "through judicial interpretation").

EPA must revise the final rule and preamble to, among other things:

1. Accurately reflect Congressional intent with respect to the regulatory compliance exemption;
2. Remove unsupported assumptions regarding whether facilities subject to methane regulations will be above or below the WEC thresholds;
3. Limit noncompliance to emissions limits and work practice standards;

(4) Limit noncompliance to those circumstances where enforcement actions result in penalties and a determination that the WEC Regulatory Compliance Exemption is unavailable;
(5) Ensure that EPA can determine availability of the Regulatory Compliance Exemption upon adoption of each state or federal OOOOc plan; and
(6) Ensure that EPA makes equivalency determinations (particularly with respect to NSPS OOOOb) immediately.

a) EPA misinterprets Congress's intent with respect to the regulatory compliance exemption

EPA states that it believes the Congressional intent of the Regulatory Compliance Exemption was two-fold: (1) to be implemented such that the WEC acts as a bridge to full implementation of the NSPS OOOOb and EG OOOOc by encouraging methane reductions in the near term while state plans are being developed; and (2) encouraging timely implementation of requirements in state and federal plans. EPA then uses this interpretation of Congressional intent as the basis for additional erroneous conclusions – namely, (1) that no operator may avail themselves of the Regulatory Compliance Exemption until all states (and the federal government, as necessary) have had OOOOc plans approved by EPA (for state plans) or promulgated federal plans (herein "state and federal OOOOc plans") and (2) that EPA must wait until all state and federal OOOOc plans are approved or promulgated to determine whether those NSPS OOOOb and EG OOOOc plans will affect equivalent emissions reductions as the proposal from November 2021 would have done.

EPA provides no explanation for how the plain reading of the statutory text supports its conclusion. The statute, on its face, provides no indication of such an intent, and states no such reasons for the basis of the exemption. However, exemptions from the fee were clearly intended to reward and incentivize compliance with the regulations – regulations that were themselves designed to reduce emissions.

Further, EPA cites no legislative history to support its position, and the legislative history that exists does not support EPA's interpretation of Congress's intent. Rather, the legislative history provides that the WEC is intended to reduce methane emissions, create a clean energy technology bank, and fund wildlife resiliency efforts and clean energy infrastructure. 168 Cong. Rec. H7577-02 (2022). In contrast, EPA's reading suggests that the primary intent of the Inflation Reduction Act in implementing the WEC was to address gaps in timing of finalization of NSPS OOOOb and state and federal OOOOc plans. Nothing in the legislative history supports such an interpretation. A more realistic interpretation is that the Regulatory Compliance Exemption was intended to provide an exemption for entities that were otherwise incurring the costs associated with complying with extensive methane emissions reduction requirements. If the intent had been for the WEC to function as a bridge until finalization of NSPS OOOOb and state and federal OOOOc plan, then Congress would have eliminated the WEC upon such occurrence. However, Congress did not propose such elimination and thus, there is no evidence that the WEC was intended to act as a bridge to anything.

Even if EPA were correct that Congress intended to incentivize quicker implementation of state and federal OOOOc plans, EPA's interpretation of the Regulatory Compliance Exemption works directly against any such intent. If *no* states' WEC Applicable Facilities may enjoy the benefit of the Regulatory Compliance Exemption until *all* state and federal OOOOc plans have been adopted, there is simply no incentive for states to adopt and obtain approval of their plans more quickly. This is particularly true given that different states will have different resources available, differing levels of experience with rulemaking, and other factors that may make development of a OOOOc plan more or less difficult.

And as we explain in more detail below in Section V(f) and (g), EPA's reading of the statutory text in this regard is not plausible. Instead, the proper reading of the text requires that a WEC Applicable Facility should be eligible for the Regulatory Compliance Exemption once all states within which the WEC Applicable Facility has affected or designated facilities have a state or federal OOOOc plan in effect.

b) EPA provides no basis for its conclusion that facilities compliant with NSPS OOOOb and EG OOOOc will likely be below the WEC thresholds

EPA states that:

> WEC applicable facilities containing CAA section 111(b) and (d) facilities that are in compliance with the applicable standards are likely to have emissions below the thresholds specified in section II.B of this preamble due to mitigation resulting from meeting the methane emissions requirements of NSPS OOOOb or EG OOOOc-implementing state and Federal plans and therefore would not be expected to incur charges under the WEC program.

89 Fed. Reg. at 5323. EPA provides no basis for its conclusion on such a technical issue. The WEC will be based on emissions intensity factors that are set forth in the statute. NSPS OOOOb/EG OOOOc do not contain emissions intensity requirements. Rather, they contain command and control regulations that mandate emissions standards and work practice standards designed to target reductions from specific units or equipment. EPA has provided no nexus or correlation between the emissions reductions expected from NSPS OOOOb/EG OOOOc and the emission intensity thresholds established in the IRA that support or justify its conclusions. Whether EPA's conclusion proves accurate in some instances (or even many) is irrelevant. EPA should not make such broad statements or conclusions (which may then be used to set expectations regarding emissions from NSPS OOOOb/EG OOOOc subject facilities).

AXPC does not believe that Congress had any understanding as to whether compliance with NSPS OOOOb/EG OOOOc would result in most facilities being below the waste emissions charge threshold. In fact, the existence of the Regulatory Compliance Exemption suggests that Congress expected otherwise. While EPA acknowledges that there will be some applicable facilities that are complying with NSPS OOOOb and EG OOOOc that are above the waste emissions thresholds, EPA appears to suggest that these would be limited exceptions. And EPA's apparent expectation that these will be limited exceptions then appears to support its creation of a rigorous, unattainable Regulatory Compliance Exemption. In short, EPA ignores the consequences that may result from implementing the Regulatory Compliance Exemption such that it is unachievable and likely underestimates the number of applicable facilities that are substantially and materially in compliance with NSPS OOOOb/EG OOOOc yet will still owe substantial fees under the WEC.

EPA cannot conclude that facilities compliant with NSPS OOOOb and EG OOOOc will not be subject to the WEC based on whims. It must provide specific evidence to support a technical conclusion and should not establish inaccurate and erroneous expectations regarding whether and how NSPS OOOOb and EG OOOOc will specifically relate to the waste emissions thresholds. Here, there is no reason that EPA needs to arrive at this conclusion and AXPC requests that EPA withdraws its unfounded statements.

AXPC provides several reasons that it believes EPA's conclusion is not only unsupported but ignores recent changes that EPA itself has proposed to Subpart W and the potential consequences for WEC

Applicable Facilities. To the extent that EPA relied upon any data in arriving at its conclusion, it appears likely (given that recent proposed changes to Subpart W have not yet been finalized) that EPA was basing any conclusions on existing Subpart W reporting and emissions factors in existing Subpart W. See Regulatory Impact Analysis of the Proposed Waste Emission Charge at 2-4. However, as noted in AXPC and other industry stakeholder comments on the proposed revisions to Subpart W, EPA has proposed to substantially increase certain emissions factors for certain equipment – including equipment that either will be difficult to mitigate or that is not equipment addressed by NSPS OOOOb/EG OOOOc (see e.g., use of pilot flame monitoring data, flowback estimates, among others). As noted in comments from AXPC and other industry stakeholders on Subpart W, EPA's proposed revisions to Subpart W will likely now result in the overestimation of emissions in certain categories – and these overestimated emissions may well result in many operators being above the WEC threshold – even for WEC Applicable Facilities that are materially compliant with NSPS OOOOb/EG OOOOc.

These considerations are one of the key reasons that AXPC and other industry stakeholders have been requesting that EPA take a more thoughtful and coordinated approach with respect to Subpart W revisions and the WEC rule. These issues are inherently tied together, and Congress specifically directed EPA to undertake the difficult work of coordinating the two – in part to ensure that an accurate inventory is being submitted. Specifically, Congress required that:

> [n]ot later than 2 years after August 16, 2022, the Administrator shall revise the requirements of Subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.
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> 42 U.S.C. § 7435(h).

AXPC does not believe that many of the proposed revisions to Subpart W appropriately reflect emissions and will in fact overstate emissions. For example, Subpart W proposes to allow operators to only account for combustion efficiencies of either 92 or 95 percent for flares and enclosed combustion devices depending on whether the combustion devices must comply with NSPS OOOOb/EG OOOOc control device requirements. Both values are too low in light of the rigorous control device requirements in NSPS OOOOb/EG OOOOc and recent studies. At a minimum, these revisions and increased factors have not likely been considered by EPA in its unsupported statements regarding the relationship between NSPS OOOOb/EG OOOOc and an emissions intensity threshold. EPA must take a step back and ensure that its efforts regarding amendments to Subpart W and its finalization of the Proposed Rule are coordinated, thoughtful, and consistent.

AXPC also incorporates by reference its comments filed on the proposed revisions to Subpart W in this regard, *see* EPA-HQ-OAR-2023-0234-0295 at page 28, and reproduces them here due to concern that EPA may take the position that incorporation by reference is not a sufficient means of placing them before EPA in this rulemaking docket. EPA obviously did not heed these comments, but neither has it given any explanation in the instant proposal why it can disregard them and continue to treat the Subpart W and WEC rulemakings as separate rulemakings in violation of the statute and the fundamental obligation to conduct its rulemakings in a rational manner.

We particularly reiterate from our Subpart W comments the following observations: As a threshold matter, EPA cannot legally or rationally treat the Subpart W rulemaking as separate and independent from its forthcoming proposed implementation of the MERP's "waste emissions charge program." ... Congress did not intend EPA to proceed this way. To the contrary, it directed EPA to make revisions to Subpart W so that both reporting under Subpart W and the calculation of WEC meet certain criteria. When submitting Subpart W comments, regulated companies were in the dark as to how EPA would interpret and implement the WEC program. And now, operators remain in the dark regarding how EPA will finalize amendments to Subpart W. This deprives them of the substance of their right to provide informed comment on the significance of the current Proposed Rule with regard to how the changes EPA plans for Subpart W will interact with EPA's implementation of the WEC.

c) EPA's implementation of the regulatory compliance exemption should evaluate compliance only with the emissions limits and work practice standards in NSPS OOOOb and EG OOOOc (and state and federal plans thereunder)

EPA acknowledges that CAA 136(f)(6)(A) does not specify the definition of compliance for the purposes of the exemption, and notes that many different types of compliance deviations or violations can occur. EPA proposes that under the Regulatory Compliance Exemption, a WEC applicable facility must be in full compliance with the methane emissions requirements of the applicable NSPS (OOOOa and OOOOb) and state and federal OOOOc plans at all affected and designated facilities contained within that WEC applicable facility. 89 Fed. Reg. at 5344-45. EPA interprets full compliance as no deviations or violations from the requirements, including quantitative emissions limits, work practice standards, monitoring, recordkeeping, and reporting. EPA bases its interpretation on the lack of "mitigating language" and its interpretation that Congress intended the reference to compliance with requirements to mean all requirements. However, EPA does not provide reasoning or support for why the variation in types of requirements means that they all must be considered in relation to the regulatory exemption for the methane emissions charge. EPA cannot merely point to the absence of definitional language, without considering the purpose of the statute; properly considering statutory purpose suggests that Congress did not intend that the regulatory compliance exemption required compliance with *all* requirements listed in the NSPS.

EPA's finalization of this proposal should provide that the Regulatory Compliance Exemption will be assessed only against NSPS OOOOb and EG OOOOc, not against NSPS OOOOa or any future potential NSPS or EG methane regulations on this sector under CAA section 111. EPA only mentions its proposal to assess compliance status for purposes of the regulatory compliance exemption with respect to NSPS OOOOa once, 89 Fed. Reg. at 5344, and EPA does not offer any statutory construction or other substantive discussion of why it proposes to include NSPS OOOOa in its regulatory-compliance assessments. The proper reading of the statute is that Congress did not intend EPA to do so.

While it is true that the introductory clause of CAA 136(f)(6)(A), viewed in isolation, speaks generally of "methane emissions requirements pursuant to subsections (b) and (d) of section 7411," these words must be read in context. The sub-provision at CAA 136(f)(6)(A)(ii) refers specifically to the November 2021 proposal of what has recently been finalized as NSPS OOOOb and the accompanying EG OOOOc, and *these* are the requirements to which Congress refers in the root text of CAA 136(f)(6)(A). Furthermore, while we disagree with EPA that Congress intended the Regulatory Compliance Exemption to incentivize quicker adoption of requirements under state or federal OOOOc plans, we observe that this construction of the statute proceeds from the same assumption as our reading does here: that Congress in the Regulatory Compliance Exemption contemplated assessing eligibility for that exemption against the rulemaking initiated with the November 2021 proposal, and not for other standards.

Proceeding as EPA proposes and assessing compliance against NSPS OOOOa in addition to the regulations Congress intended will create confusion. State plans should address the relationship between facilities that are NSPS OOOOa and those that are subject to the state OOOOc plan. State plans will provide implementation timeframes for facilities to come into compliance with the OOOOc plans, and EPA has appropriately concluded that those requirements only need be in place, not implemented, to qualify for the Regulatory Compliance Exemption. However, to the extent that an NSPS OOOOa affected facility remains as such until actual implementation of the OOOOc requirements, there could be a period of time where OOOOa continues to apply after EPA has signed off on the Regulatory Compliance Exemption. NSPS OOOOa compliance should not be part of the analysis in determining whether the Regulatory Compliance Exemption is available during that period.

While it is clear why requirements such as monitoring, reporting, and recordkeeping are part of sections 111(b) and 111(d), they need not be applied to determine compliance for purposes of this exemption. Considerations such as monitoring, recordkeeping, and reporting, while required by CAA section 111, should not be included in determinations of compliance for the Regulatory Compliance Exemption because they do not directly impact emissions or the amount of emission reductions.

The plain language of the statute, and Congress's intent, clearly demonstrate that the purpose of the emission charge and the regulatory compliance exception is to incentivize facilities to reduce actual methane emissions. Since the focus is on the actual levels of emissions, and less on the process requirements such as recordkeeping, reporting, and monitoring, compliance should be established where an operator has met all quantitative limits and work practice standards. This is in line with the calculation process for the charge which determines the charge based on the metric tons of methane emissions above the threshold requirement. A deviation in monitoring, recordkeeping or reporting will not impact this calculation, and thus should not impact whether an operator is in compliance for the exception.

This is evidenced by EPA's discussion of the demonstration that it will make to meet Clause (ii) (as described below). Specifically, EPA notes that Congress directs EPA to compare the emissions that would have been achieved if the NSPS OOOOb/EG OOOOc 2021 Proposal were finalized against the finalized NSPS OOOOb/EG OOOOc. This evidences that Congress was focused on the *emissions reductions* that the NSPS OOOOb/EG OOOOc would achieve (through emissions standards or work practice standards), not on requirements related to monitoring, recordkeeping, and reporting. Thus, only those provisions of NSPS OOOOb and state or federal OOOOc plan that constitute an emission limits or the non-recordkeeping and reporting provisions of a work practice standard should be considered in determining eligibility for the Regulatory Compliance Exemption.

d) EPA must revise the reporting requirements for the regulatory compliance exemption and must not base availability of the regulatory compliance exemption on self-reported deviations

EPA's Proposed Rule indicates that in order to obtain the Regulatory Compliance Exemption a facility must have no deviations or violations of the methane emissions requirements (including monitoring, recordkeeping, and reporting) promulgated pursuant to NSPS OOOOb or state or federal OOOOc plans. EPA proposes that operators represent this status and appears to require reliance on operators' annual reporting requirements under the NSPS to require operators to self-report whether there are deviations or violations of the methane emissions requirements. AXPC strongly disagrees with numerous aspects of this proposal by EPA.

First, operators should not be required to report unless they are seeking a Regulatory Compliance Exemption. If an operator knows that it cannot obtain the Regulatory Compliance Exemption (either because its emissions are below the WEC thresholds or because an operator has itself concluded that it cannot meet the Regulatory Compliance Exemption), then that operator should be able to elect not to report and acknowledge that it does not seek the Regulatory Compliance Exemption. EPA should not mandate reporting by individuals that are not seeking the Regulatory Compliance Exemption – either because they are not eligible or because they cannot obtain it. An exemption is precisely that: an exemption. If an operator does not want an exemption (whether the Regulatory Compliance Exemption, the permitting delay exemption or the plugged well exemption), then EPA should not require an operator to submit any materials regarding that exemption.

Second, deviation reporting may not always reflect a violation appropriate for pursuit of enforcement or may often not reflect noncompliance that should result in ineligibility for the Regulatory Compliance Exemption. Rather, a determination of noncompliance should be based only on those circumstances where an operator has an enforcement action that has resulted in penalties for noncompliance with emission limits and work practice standards under NSPS OOOOb or state or federal OOOOc plans **and** where EPA has determined that such enforcement action precludes eligibility for the Regulatory Compliance Exemption. By limiting noncompliance to those circumstances where an operator and relevant authority have entered into a settlement agreement requiring the payment of penalties or an adjudication resulting in payment of penalties, EPA would ensure proper and fair due process under the law. Further, requiring either the settlement agreement or the adjudication to include a finding regarding the availability of the Regulatory Compliance Exemption would allow EPA to utilize its discretion to acknowledge when deviations or violations are not substantively or materially impacting emissions such that an operator should retain eligibility for the Regulatory Compliance Exemption.

Establishing such a basis for determining eligibility for the Regulatory Compliance Exemption is needed to ensure that EPA does not inadvertently disincentivize self-audits or self-investigation or unduly punish operators who embrace a rigorous deviation reporting program. EPA invested significant time over the last 5 to 10 years to develop programs and incentives for operators in the oil and gas sector to complete self-audits on their existing assets or on newly acquired assets. EPA's interpretation of the Regulatory Compliance Exemption – i.e., that all deviations or violations identified by the operator itself will preclude eligibility – will strongly disincentivize self-audits.

The statutory text leaves room for EPA to determine the extent and meaning of the term "in compliance." Here, EPA has elected in its proposed rule to interpret the term in such a manner that it makes the exemption fundamentally unavailable. This is particularly true for the onshore and gathering and boosting sectors where each WEC applicable facility has dozens to thousands of affected and/or designated facilities/sites within its boundaries. It is unclear whether Congress understood in adopting the WEC provisions of the IRA that onshore and gathering and boosting applicable facilities can contain dozens to thousands of affected and/or designated facilities. It makes no logical sense that Congress would intend that a deviation at one affected facility (e.g., one storage tank) would then make ineligible for the Regulatory Compliance Exemption the remaining thousands of storage tanks that are in compliance within that same basin. Certainly Congress intended that the Regulatory Compliance Exemption be available to all operators subject to the 111(b) and (d) requirements. EPA's current approach does not give effect to the statutory intent or requirement, and is therefore not a reasonable interpretation and application of the statutory text. AXPC's proposal would provide EPA and operators the ability to discuss and determine when noncompliance should preclude use of the Regulatory Compliance Exemption.

In addition, or in the alternative, EPA should develop a threshold or percentage of compliance (again only with respect to emissions limits and work practice standards) that a WEC applicable facility must achieve. EPA must provide meaningful opportunity for operators to obtain the Regulatory Compliance Exemption and flawless compliance should not be mandated in order to obtain the Regulatory Compliance Exemption. This is particularly true given that certain interpretations and requirements that EPA has established in NSPS OOOOb and EG OOOOc make strict and flawless compliance even with emissions standards and work practice standards virtually impossible. For example, EPA has proposed that any emission from a cover or closed vent system constitutes a deviation/violation of the standard. As AXPC and other parties noted in their comments on NSPS OOOOb/EG OOOOc, emissions cannot be precluded from covers or closed vent systems (even with complete and compliant design and operation). Unfortunately, as these interdependent rulemaking timelines overlap, commenters do not yet have a full understanding of whether, if and how these (and other) issues will be addressed by EPA or the courts in response to any reconsideration or review petitions (each of which would be filed after the close of this comment period). EPA must look for a path forward that does not mandate flawless compliance that is not practically achievable, in the same way this rule must not incorporate such a flawed expectation in order to obtain the Regulatory Compliance Exemption. AXPC has proposed one path here – i.e., limit the provisions to which the compliance demonstration applies and limit non-compliance to those that have completed the full enforcement process. In addition, or in the alternative, EPA should consider and adopt some other alternative that would give meaning and availability to the Regulatory Compliance Exemption.

e) EPA's discussion regarding netting of WEC applicable facilities creates significant confusion

EPA determines in the Proposed Rule that "if a facility's emissions are not subject to the WEC, either because the facility is not a WEC applicable facility, or because a WEC applicable facility receives the Regulatory Compliance Exemption,[6] that facility's emissions do not factor into the netting of emissions for a WEC obligated party." 89 Fed. Reg. at 5329. In other words, "only WEC applicable facilities may net, and only WEC applicable emissions may be netted." *Id*. Based on a related analysis, EPA further

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[6] AXPC notes that this discussion assumes the final adoption of a Regulatory Compliance Exemption that can be attained. As currently proposed, AXPC believes that no (or virtually no) WEC Applicable Facilities will be able to receive the Regulatory Compliance Exemption and this erroneous interpretation for facilities receiving the exemption will be irrelevant.

concludes that WEC Applicable Facilities with emissions below the waste emissions threshold are not eligible to receive the Regulatory Compliance Exemption. Thus, EPA apparently concludes that: (1) WEC Applicable Facilities with waste emissions above the threshold may receive the Regulatory Compliance Exemption but may not net; and (2) WEC Applicable Facilities with waste emissions below the threshold may not receive the Regulatory Compliance Exemption but may net. While this result appears to be a reasonably practical outcome with respect to netting and the Regulatory Compliance Exemption, EPA's position and its logic are confusing. Instead, EPA should encourage all WEC Applicable Facilities to both: (1) achieve emissions below the waste emissions threshold; and (2) to maintain compliance such that the WEC Applicable Facility is eligible for the Regulatory Compliance Exemption. EPA's stated interpretations do not on their face appear to support these goals. Instead, EPA should simply conclude that a WEC Applicable Facility that receives the Regulatory Compliance Exemption remains eligible to net (at the operator's election). In fact, AXPC believes that netting should always be at the option and discretion of the operator. There should be no forced netting. Rather, operators should be able to elect when to net (and as discussed above, should be able to net through parent companies). And, as noted above, operators should be able to voluntarily report Subpart W emissions for facilities that do not exceed the threshold and use those emissions for netting purposes.

AXPC agrees with EPA that nothing should require an operator of a WEC Applicable Facility that does not seek the benefits of the Regulatory Compliance Exemption to have to undertake the necessary resources to demonstrate compliance with the Regulatory Compliance Exemption. However, an operator should be able to make the demonstration that it meets the Regulatory Compliance Exemption even if it has emissions below the WEC threshold. This is important in the event that an operator submits emissions calculations below the WEC threshold but where subsequent calculations (either the operators or through the verification process at EPA) evidence emissions above the WEC threshold. In that case, an operator who was below the WEC threshold initially may need to subsequently rely upon the Regulatory Compliance Exemption.

f) Clause (i) of the regulatory exemption should be met for a WEC applicable facility once all state (or federal) plans covering that WEC applicable facility are approved (or promulgated)

As noted above, Congress identified two prongs that must be met in order for the Regulatory Exemption to be available for an operator of a WEC Applicable Facility. In the first prong (set forth in 42 U.S.C. § 136(f)(6)(A)(i)(herein "Clause (i)"), Congress indicated that Clause (i) requirements have been satisfied when "methane emissions standards and plans …. have been approved and ***are in effect in all States with respect to the applicable facilities***." (Emphasis added.) EPA proposes to interpret the words "are in effect[7] in all States with respect to the applicable facilities" as follows:

> The EPA further proposes to interpret ''all states'' in CAA section 136(f)(6)(A)(i) to mean that every state with an applicable facility (i.e., all states with Subpart W facilities containing CAA section 111(b) or (d) facilities) must have an approved plan (state or Federal) before the determination can be made.
>
> 89 Fed. Reg. at 5337/3.

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[7] EPA interprets "in effect" as when an Administrator determination regarding a federal or state OOOOc plan has been made, not when the applicable requirements in the state and federal plans are fully implemented. As noted in Section V(g) below, AXPC agrees with this part of EPA's interpretation.

EPA claims that this approach is aligned with a plain reading of the statutory text. But this is not a reasonable interpretation of this statutory phrase, either on its own terms, in context, or when considering Congress's underlying purpose in enacting the Regulatory Compliance Exemption provision. First, as noted above, it directly contradicts what EPA itself says is a major purpose for the exemption: incentivizing timely implementation of state-plan requirements. While AXPC does not agree with EPA that the Inflation Reduction Act was intended to incentivize timely implementation of state-plan requirements, EPA's internal inconsistencies evidence the problems with its interpretations of the statutory language.

EPA's interpretation ignores a critical part of the provision – the modifier – "with respect to the applicable facilities." Statutes must be read as a whole, and the "cardinal principle of interpretation [is] that courts must give effect, if possible, to every clause and word of a statute." *Parker Drilling Mgmt. Servs., Ltd. v. Newton*, 139 S. Ct. 1881, 1890 (2019). The term "the applicable facilities" refers not to *all facilities* nationwide, but to the *specific* facilities whose eligibility for the Regulatory Compliance Exemption is in question. Giving meaning to all terms of the statute results in the conclusion that a facility is not eligible for the Regulatory Compliance Exemption until all states in which the applicable facility is located have a state or federal OOOOc plan in effect. As for the words "in all states," they refer not to *all* states that have any existing sources (as EPA proposes to read them), but rather to all states in which the WEC obligated party has equipment in a given facility. EPA itself in the proposal repeatedly notes that there are facilities which extend across state lines. *See, e.g.*, 89 Fed. Reg. at 5399. All that these words provide is that no facility is eligible for the Regulatory Compliance Exemption for existing sources until all states in which that facility is located have a state or federal existing-source plan in effect.

EPA states that its "proposed approach for implementing the Regulatory Compliance Exemption is based on a *plain reading* of the statutory text in CAA section 136(f)(6)," 89 Fed. Reg. at 5336/2 (emphasis added). However, this is patently not the case. First, EPA itself admits that it departs from a literal reading of this section when it proposes to interpret the phrase "'plans pursuant to subsection. . . (d) of section 111'" as "includ[ing] the promulgation of a Federal plan where the EPA determines that one or more states have failed to submit an approvable state plan, as that is the only way a plan pursuant to CAA section 111(d) would take effect in those states." 89 Fed. Reg. at 5337/3 (ellipsis in original). While AXPC agrees with EPA with respect to this interpretation, such interpretation is simply not a "plain reading" of the statutory text. Rather, it requires interpretation based on the structure and function of CAA Section 111, knowledge of which should be imputed to Congress as part of the background understanding of the text that it enacted here.

The entire statutory phrase at issue in Clause (i) reads:

> methane emissions standards *and plans* pursuant to subsections (b) *and* (d) of section 7411 of this title have been *approved* and are in effect in all States with respect to the applicable facilities
>
> CAA Sec. 136(f)(6)(A)(i) (emphases added).

Like EPA's interpretation that Clause (i) includes adoption of federal plans (as applicable), this provision demonstrates the need to consider the context of Clean Air Act Section 111 in interpreting these provisions. EPA does not "approve" its own federal existing-source plans, it *promulgates* them. And once the Agency has made this departure from the text's literal meaning, it loses any remaining justification for its claim that a plain reading of "in all states" requires it to wait until *all* states with *any* applicable facilities in them *anywhere* in the country have a plan in effect before affording the regulatory-compliance exemption to any facility. As with its reading of the "plans pursuant" provision, the correct interpretive approach here is to look for reasonable Congressional intent in light of the other statutory section referenced here and the nature of the regulatory problem and sector at issue.

Second, the phrase "pursuant to subsections (b) and (d) of section 7411" likewise requires a reasonable interpretation in context rather than a literal one—and here, unlike with its interpretation to include its own federal plans within the meaning of plans "approved" under Subsection (d), EPA's interpretation is not correct.

Here is EPA's interpretation:

> The EPA proposes to interpret the language in CAA section 136(f)(6)(A)(i) to mean that this temporal requirement is only met when *both* (1) emission standards for new sources under CAA section 111(b) are promulgated and in effect and (2) all state plans for existing sources pursuant to an EG issued under CAA section 111(d) have been approved by the EPA and are in effect.

89 Fed. Reg. at 5337/2. This is not the correct interpretation of the statutory text. The new-source and existing-source authority under Section 111(b) and (d), respectively, are mutually exclusive, *see Section* 111(a)(6) ("The term 'existing source' means any stationary source other than a new source."). Again, Congress was speaking at a high level in Section 136(f)(6), and again, EPA's interpretation of the Congressional intent should be informed by the text and structure of Section 111, which (f)(6) explicitly references. Because new-source regulation under 111(b) will be in effect once the recently finalized NSPS OOOOb is in effect, *i.e.*, May 7, 2024, *see* 89 Fed. Reg. at 16820/1, there is no reason for EPA to wait any longer past that date, and in particular no reason for it to wait until *any* state plan is in effect, let alone *all* state plans are in effect, before determining that new-source methane regulations are "in effect" with respect to all new sources in all states.

EPA instead should adopt the

> alternative [that] would involve a determination for methane emissions standards after the promulgation of final emissions standards for CAA section 111(b) facilities and then determinations on a state-by-state basis as each state plan containing emissions standards for CAA section 111(d) facilities were submitted and approved by the EPA (or a Federal plan was promulgated where a state did not submit an approvable plan).

89 Fed. Reg. at 5338/1. The only reason EPA gives for not adopting this approach is its belief that the statute requires "that emissions standards and plans must be approved and in effect in *all* states" before it can make the predicate determinations for the regulatory compliance exemption, but as explained above, that is not the correct reading of the statute.

g) EPA need not and should not wait until all state or federal OOOOc plans are approved or promulgated to make equivalency determinations under clause (ii)

Clause (ii) of the Regulatory Compliance Exemption requires that EPA make a demonstration that compliance with the requirements described in Clause (i) "will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review” (86 Fed. Reg. 63110 (November 15, 2021)), if such rule had been finalized and implemented.” EPA proposes to conduct the analysis for purposes of this equivalency determination at a national level, comparing the national-level emissions reductions that would have been achieved under the NSPS OOOOb/EG OOOOc 2021 Proposal (if finalized as proposed) against those that will be achieved upon implementation of the final NSPS OOOOb/EG OOOOc. Further, EPA proposes that the two determinations (1) federal regulation equivalency and (2) state plan equivalency be made together, at one time, for NSPS OOOOb and all state and federal OOOOc plans.

EPA’s proposal that it make both determinations at once is based on their interpretation that the language of the statute calls for “one single determination.” However, as discussed throughout, this interpretation is not in line with principles of statutory construction, or the purpose of the statute. The full sentence reads that plans are “approved and are in effect in all States with respect to the applicable facilities” and as discussed elsewhere, should not be read to refer to all applicable facilities nationwide. Additionally, EPA states that the determination cannot be made until standards and plans are in place in all states because the equivalency determination must be made on a nationwide scale.

We do not agree that EPA must make this determination after all plans are approved and in effect. EPA’s focus on “a” determination is very unpersuasive. Furthermore, the singular use of “a” within the phrase “upon a determination by the Administrator” is countered by the singular word “an” within the phrase “[c]harges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements.” This phrase clearly contemplates that the Regulatory Compliance Exemption is being made for particular applicable facilities, and *that* is the correct frame through which the subsequent phrase “a determination” should be made.

EPA’s interpretation would put operators in States with timely plans at the mercy of other States. This would essentially eliminate the exemption for the first several years. A two-step analysis, that first determines equivalency of NSPS OOOOb, and then determines equivalency of NSPS OOOOc and state plans, will eliminate wasted time and resources because if NSPS OOOOb does not meet the equivalency determination, then neither will NSPS OOOOc.

EPA in fact has all the information it needs to make the equivalency determination *now*, and that determination is ripe for the making now (or at latest when the March 2024 final rule takes effect in May 2024). In the November 2021 proposal, EPA made certain projections as to the emissions reductions it projected would result from implementation of the proposal, and in the March 2024 final rule, EPA issued updated versions of the projections. Its March 2024 projections *exceed* the November 2021 projections (even adjusting for the longer time frame for which the final rule makes these projections), *compare* 86 Fed. Reg. at 63257/3 (Nov. 2021 proposal) *with* 89 Fed. Reg. at 17017/2-3 (Mar. 2024 final rule), demonstrating that compliance with the final rule will meet the standard articulated at CAA Sec. 136(f)(6)(A)(ii).

EPA therefore can and should make the equivalency determination now. However, even if EPA rejects this approach, at the very least, a state-by-state approach is more aligned with Congress’s intent than EPA’s proposed approach, because it will ensure efficiency in the process and ensure more operators are eligible for the exemption. The state determination can be done in parallel with the evaluation and approval of each state’s plan (or in parallel with EPA’s promulgation of a federal plan for a state’s existing sources). Under this approach, once a state plan is approved (or a federal plan is promulgated), the EPA can also make a determination of equivalency. Further, the approach is simplified if EPA has already determined that NSPS OOOOb is equivalent, because then the state plan's approval means it meets the requirements of 111b and 111d, and thus it is equivalent.

CAA Sec. 136(f)(6)(A)(ii) provides that the Regulatory Compliance Exemption requires a determination by the Administrator that the regulatory requirements referenced in (A)(i) "will result in equivalent or greater emissions reductions as would be achieved by the [November 2021 proposal], if such rule had been finalized *and implemented*." (Emphasis added.) The "implementat[ion]" of existing-source regulation pursuant to both Section 111(d)(1) (state plans) and (d)(2) (federal plans) entails the states' prerogative (under (d)(1) to "take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies," and EPA's own *obligation* (under (d)(2)) to "take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies." (This language is what EPA refers to by the acronym RULOF, for "remaining useful life and other factors.").

In other words, RULOF considerations *are part of* existing-source rule implementation, as the text and structure of Section 111(d) clearly demonstrate, and Congress was aware of this fact when it enacted the Regulatory Compliance Exemption provision at Section 136(f)(6). EPA is therefore wrong to suggest, *see* 89 Fed. Reg. at 5342, that the statutory RULOF authority somehow prevents it from making an equivalency determination with respect to existing-source plans until those plans are approved (for state plans) or promulgated (for federal plans). RULOF considerations would have been available to states (and mandatory for EPA) under Section 111(d) "if [the November 2021 proposal had been finalized and implemented" in the same manner as those considerations are available to states (and mandatory for EPA) now that the March 2024 final rule has been finalized and will be implemented. Congress's contemplation of the finalization and implementation of the November 2021 proposal necessarily entails exercise of the statutorily available RULOF authority. Therefore, questions of RULOF are no barrier to EPA making its equivalency determination now.

h) AXPC agrees with EPA on certain conclusions

AXPC agrees with EPA's interpretation that the Regulatory Compliance Exemption should be available when state or federal plans are in effect (see elsewhere for disagreement that all state or federal plans need to be adopted) even if full implementation of those requirements is not required until a future date.

AXPC further agrees with EPA's interpretation that operators are eligible for the exemption for the entire calendar year during which the requisite determinations that the regulatory exemption is available occur (for example, if June 2027, then the whole of 2027). This should not be for a portion of the reporting year or for the next reporting year. It should be noted that the typical calendar-year cadence described in the proposed rules for Subpart W/WEC filings may be out of step with OOOOb as the first compliance reporting is currently expected to be in July or August.

VI. Definitions should reference 40 CFR 98 Subpart W

EPA had defined some terms the same and some terms differently from 40 CFR 98 Subpart W. To avoid conflicting definitions and having to update definitions in two places, EPA should instead simply reference the definitions in 40 CFR 98 Subpart W.

VII. EPA should not require the operator to pay for audits

EPA should not require the operator to pay for a third-party audit of the WEC. EPA should conduct the audit or pay for the auditors. EPA's proposal in this regard presents the daunting prospect of unknown costs on operators.

VIII. EPA should exclude stationary fuel combustion emissions reported under Subpart W that could otherwise be reported under Subpart C

The proposed WEC rule arbitrarily treats stationary fuel combustion emissions differently depending on whether those emissions occur at a facility reporting under Subpart W or at a facility in an industrial segment such as gas processing or transmission that reports the same type of combustion emissions under Subpart C. This inconsistency arises not from any technical difference or legal reason but merely from how EPA has defined "WEC applicable facility" to include all emissions reported under Subpart W, without accounting for the arbitrariness of including stationary fuel combustion emissions that must be reported under Subpart W due to the type of oil and gas facility. Inclusion of fuel combustion emissions in the WEC facility emissions is inappropriate because methane emissions from fuel combustion are not waste. Emissions from fuel combustion (e.g., engines) occur through routing of natural gas to fuel combustion equipment (such as engines) for beneficial use. To correct these concerns, EPA should exclude stationary fuel combustion unit emissions that are reported under § 98.232 pursuant to § 98.232(k) (these could be defined as those that could otherwise be reported under Subpart C), from counting towards the waste emission charge.

The intent of the WEC is to encourage the reduction of methane emissions and this was effectuated in part by tying the WEC to compliance with OOOOb and OOOOc requirements.[8] EPA acknowledges this in the proposal, saying "The EPA expects that, as oil and gas operations implement the requirements of final NSPS OOOOb and the plans issued and approved pursuant to EG OOOOc (and undertake other methane mitigation voluntarily or due to other Federal or state regulations), total reported Subpart W facility methane emissions would decline."[9] It follows that Congress did not intend to subject an upstream operator to WEC obligations resulting from stationary fuel combustion emissions, when these emissions are separate and unrelated from the issue of whether a facility's methane emissions associated have been reduced as much as practicable pursuant to NSPS OOOOb or OOOOc requirements. Further, as noted above, these emissions are not waste emissions. Excluding upstream operators' stationary fuel combustion emissions that could otherwise be reported under Subpart C from the WEC facility emissions calculation is congruent with the intent of the WEC to incentivize the reduction of methane emissions in accordance with NSPS OOOOb and OOOOc.

Therefore, in the final rule, EPA should exclude stationary fuel combustion emissions reported under Subpart W that could otherwise be reported under Subpart C from the calculation of whether the facility owes a WEC obligation.

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[8] See 42 U.S.C. § 7436(f)(6)(A) (relating to the exemption for "compliance with methane emissions requirements. . . standards and plans").

[9] 89 Fed. Reg 5318 at 5345 (Jan. 26, 2024).

INDEPENDENT PETROLEUM
ASSOCIATION OF AMERICA

March 26, 2024

U.S. Environmental Protection Agency
EPA Docket Center
Air and Radiation Docket
Mail Code 28221T
1200 Pennsylvania Avenue NW,
Washington, DC 20460.

Docket Number: EPA–HQ–OAR–2023–0434
Waste Emissions Charge for Petroleum and Natural Gas Systems

The Independent Petroleum Association of America (IPAA) submits these comments regarding the Environmental Protection Agency (EPA) proposal to implement a Waste Emissions Charge for Petroleum and Natural Gas Systems (WEC) under the Inflation Reduction Act Methane Emissions Reduction Program (Methane Tax).

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of American oil and natural gas wells, produce 83 percent of American oil and produce 90 percent of American natural gas.

In addition to the comments filed here, unless there are specific comments presented herein, IPAA endorses the comments filed by the American Petroleum Institute (API).

The Methane Tax process includes multiple features. However, a key factor in conjunction with this WEC proposal is the application of information from Subpart W. IPAA previously filed comments on the EPA proposal to modify Subpart W (EPA-HQ-OAR-2023-0234-0265). These comments are included in this submission as Appendix A.

Because the emissions calculations under Subpart W are the building blocks for calculation of the WEC, these comments will reiterate and expand on those prior comments. Then, it will address key issues in the WEC proposal.

A. Subpart W

There are several key issues within EPA's Subpart W proposal that remain unresolved and yet essential to the consideration of the WEC proposal because they define the emissions amounts that will ultimately be taxed. One of these is a fundamental issue related to the definition of a facility under the Methane Tax as it relies on Subpart W. A second issue relates to EPA's failure to properly assess emissions factors that become the emissions basis. These will be addressed below.

1. *EPA fails to properly develop a facility definition for the Methane Tax that is consistent with the Clean Air Act.*

The issue of the Subpart W facility definition is not a new one, but it has returned to focus because of EPA's choice to use it without addressing whether it is appropriate for the Methane Tax. The underlying structure of the Subpart W facility definition has been contentious since it was first proposed and adopted for the Greenhouse Gas Reporting Program (GHGRP). The principal issue continues to be that the definition fails to reflect the realities of oil and natural gas production operations. It fails to track other definitions of oil and natural gas production facilities in the Clean Air Act (CAA). EPA's default to the use of the Subpart W definition in the GHGRP context is inappropriate and not required by the Methane Tax.

IPAA has consistently recommended that EPA more properly define Subpart W facilities in the context of the general understanding of facilities within the CAA and the industry. In 2010 comments filed when the facility definition was first developed, IPAA stated the following:

> Most notably, we believe that use of the CAA denies EPA the authority to create a definition of a facility that differs from that in the CAA. EPA proposes the following definition:
>
>> Onshore petroleum and natural gas production facility means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.
>
> Under this definition, for example, all wells under common ownership along the Gulf Coast of Texas and Louisiana and deeply into the mainland of those states would be considered as one facility. This would be analogous to proposing that every McDonalds restaurant in the State of Texas should be considered as one facility because they have the same name and are franchised from a common source.
>
> Nothing in the CAA suggests that EPA can define an onshore petroleum and natural gas production facility as broadly as it proposes. In reality, the only guidance provided to EPA in the CAA resides in Section 112(n)(4)(A) where it states:
>
>> … in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose ….
>
> EPA proposes its basin approach and solicits comment on the option of using a similar approach involving "field-level reporting". In doing so, the Agency discounts the obvious choice – the well pad. Clearly, the well pad looks like a facility under the definition in the CAA and is the typical permitting unit under CAA regulations. EPA considered a well pad approach and "EPA analyzed the average emissions associated with each of the four well pad facility cases and determined that average emissions at these operations were low (from about 370 metric tons of CO2e per year to slightly less than 5,000 metric tons of CO2e per

year).” Recognizing that individual sources were small, EPA chose to create its novel basin approach.

We identified this issue in our comments to EPA’s proposal in 2009 when we stated:

> We believe that including onshore petroleum and natural gas production facilities in the reporting requirements runs counter to EPA’s focus in this proposal. EPA structured the proposal by selecting its 25,000 tons/year facility reporting threshold in part based on a cost effectiveness test to capture most of the GHG emissions while limiting excessive costs. Despite this effort, under the current proposal 43 percent of the first year capital costs to comply with the rule will be borne by the petroleum and natural gas industry to report an estimated 3 percent of the nation’s GHG emissions. Expanding the reporting requirements to onshore facilities will dramatically increase these costs unnecessarily.
>
> American petroleum and natural gas production comes from approximately 933,000 wells – roughly 500,000 oil wells and 433,000 natural gas wells. These facilities are spread across 33 states. Offshore facilities would be within the scope of the reporting requirements. EPA estimates that 50 offshore facilities would be covered under the 25,000 tons/year threshold. If EPA were to expand the reporting requirements to onshore facilities, it is highly unlikely that any production well facility would meet the reporting threshold. For example, approximately 85 percent of oil wells and 74 percent of natural gas wells are marginal wells producing less than 15 barrels/day of oil and 90 mcf/day of natural gas, respectively. Most of these operations are owned by small businesses. None of them would exceed the reporting threshold individually.
>
> EPA largely seems to recognize this reality when it states:
>
> > …this segment is not proposed for inclusion primarily due to the unique difficulty in defining a ‘‘facility’’ in this sector and correspondingly determining who would be responsible for reporting.
>
> EPA has requested comments on how to define a facility for onshore petroleum and natural gas production and whether to require reporting on a basin level. We believe that the appropriate facility definition tracks the nature of the operation – essentially a well pad which may contain one or several wells and the attendant separation and storage facilities. As we discussed above, these operations will fall well below the reporting threshold. To approach the reporting on a basin level would result in compelling this industry to use a reporting threshold far below the 25,000

> tons/year threshold required for other industries. In essence, all production operations would have to determine emissions levels by whatever estimation or monitoring requirements would apply. This would impose dramatically different costs. To put all of this in some perspective, EPA's INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990- 2007 (Released on April 15, 2009) would suggest that the GHG emissions from natural gas systems and petroleum systems account for roughly 2.3 percent of U.S. GHG emissions. EPA suggests that about 27 percent of these emissions come from onshore petroleum and natural gas production operations – or roughly 0.6 percent of U.S. GHG emissions.
>
> There is no compelling rationale to justify imposing on this segment of American industry a far costlier reporting requirement, capturing hundreds of thousands of wells many owned by small businesses, solely for the purpose of minimally improving the U.S. GHG emission inventory.

This circumstance has not changed appreciably. EPA argues that it has underestimated the amount of GHG emissions from onshore petroleum and natural gas production systems. The 2008 U.S. Inventory of Greenhouse Gases reported 131 MMTCO2e from petroleum and natural gas systems. EPA believes the emissions are 351 MMTCO2e. To put this in the same perspective as our 2009 comments, these systems would account for slightly more than 6 percent of U.S. GHG emissions and the onshore petroleum and natural gas production systems would be approximately 3.9 percent. EPA must recognize the burden it will impose on the small businesses that operate the majority of these systems.

Small Business Implications

EPA cavalierly asserts that this proposal "…will not have a significant economic impact on a substantial number of small entities." But, can this be true? Comparing numbers of wells that must report against the number of wells operated by small businesses shows a different result.

In creating its basin-level reporting approach, EPA indicates that it will capture 81 percent of the onshore petroleum and natural gas production GHG emissions. It also states – in rejecting the logical well pad facility definition – that individual well pad emissions were low. Consequently, we must conclude that EPA's definition must capture something close to 80 percent of the operating wells.

In 2008, there were 960,303 operating wells in the U.S. (525,287 oil wells and 435,016 natural gas wells, with about 7,000 of these in the federal offshore). The Energy Information Administration reports that 85 percent of these oil wells and 73.3 percent of these natural gas wells are marginal wells. Assuming a proportional distribution across wells, the following results would be produced:

	Wells Reported Under Rule	Marginal Wells Reported Under Rule
Oil Wells	417,300	354,815
Natural Gas Wells	345,213	253,041
Total	762,513	607,856

> Clearly, there will be a pervasive burden borne by America's marginal well producers. EPA is well aware that the companies operating marginal wells are dominated by small businesses. To suggest that the proposed rule will not have a significant impact on small businesses is simply incorrect.

EPA rejected these arguments with the following rationale in its publication of the GHGRP Subpart W regulations:

> We are also including two distinctive definitions of facility for onshore petroleum and natural gas production and for natural gas distribution. Defining a facility in these cases is not as straightforward as other industry segments covered under subpart W. For some segments of the industry (e.g., onshore natural gas processing, onshore natural gas transmission compression, and offshore petroleum and natural gas production), identifying the facility is clear since there are physical boundaries and ownership structures that lend themselves to identifying the scope of reporting and responsible reporting entities. However, in onshore petroleum and natural gas production and natural gas distribution such distinctions are more challenging. As explained in the April 2010 proposal, EPA evaluated existing definitions used under current regulations and determined that it was necessary to provide a unique definition of facility for each of these two segments in order to ensure that the reporting delineation is clear, avoid double counting, and ensure appropriate emissions coverage. For more information please see the preamble for the April 2010 proposal (75 FR 18608) and the Greenhouse Gas Emissions from Petroleum and Natural Gas Industry: Background Technical Support Document (EPA–HQ–OAR–2009–0923).
>
> These definitions are intended only for purposes of subpart W and are not intended to affect to definition of a facility as it might be applied in any other context of the Clean Air Act.

This commitment will no longer be true if EPA applies the Subpart W facility definition in the Methane Tax.

There is nothing in the CAA nor in the Methane Tax that justifies EPA transferring the facility definition component of Subpart W to the Methane Tax. Rather, it is more pertinent to look to other agency actions addressing the definition of oil and natural gas production facilities.

The general concept of a "facility" under the CAA revolves around a typical plant site composed of a single operation or multiple interlocking operations like a refinery or chemical plant or steel mill. Certainly, the dispersed historical nature of oil and natural gas production facilities has made defining those facilities more difficult. However, the only place in the CAA where Congress has spoken is under Section 112 where the language states:

> ...emissions from any oil or gas exploration or production well (with associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.

Where EPA is so frequently referring to the plain reading of the language of the Methane Tax in this proposal, this Congressional directive should bear strongly on EPA's interpretation.

Supporting the concept of using a tightly drawn definition of a facility is EPA's actions in defining a "major source" under its federal operating permit requirements as follows:

> *Major source* means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining "major source," a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (*i.e.,* all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987. For onshore activities belonging to Standard Industrial Classification (SIC) Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site; or if they are located on surface sites that are located within 1/4 mile of one another (measured from the center of the equipment on the surface site) and they share equipment. Shared equipment includes, but is not limited to, produced fluids storage tanks, phase separators, natural gas dehydrators or emissions control devices.

This interpretation was developed through an extensive rulemaking and did not come quickly. Yet, it, too, provides evidence that EPA can come to a rational decision on defining an oil and natural gas production facility. Significantly, this action occurred in 2016, well after the Subpart W facility definition was created.

EPA now faces a different more compelling situation than it did in 2010 when it drafted Subpart W. Congress not only created the Methane Tax, it also intended that the tax should not apply to small well producers. As Senator Manchin stated in his June 2023 letter to EPA:

- The statute clearly intends to exempt marginal wells and smaller producers from the fee.[3] EPA must make it clearly understood that those entities not subject to the current Subpart W Greenhouse Gas Reporting Program are not subject to EPA fees under MERP.
- ...
- EPA should draw reasonable boundaries around the definition of individual "facilities" (such as pad site, compressor site, or reporting field) for emissions intensity calculations so that aggregations of large amounts of disparate wells

> and gathering lines does not lead to charging a fee on marginal facilities that Congress intended to exempt or on facilities that have minimal actual emissions.

EPA's use of the facility definition from Subpart W thwarts both these mandates. EPA's sweeping scope of a facility using the American Association of Petroleum Geologists (AAPG) basins to define a facility compels small producers to aggregate all their small producing wells over huge areas, like the entire state for West Virginia or Michigan.

To give some perspective to the potential impact of the use of the sweeping facility definition under Subpart W, a few facts can provide some insight. First, it's important to understand that small business oil and natural gas producers typically need to operate hundreds of small wells across an AAPG basin to be economic. Second, looking at the most recent GHGI (providing data on 2022 emissions), it shows that the distribution of CO_2eq emissions for natural gas production wells is approximately 9 percent CO_2 and 91 percent methane (as CO_2eq). For petroleum (oil) wells the distribution is approximately 33 percent CO_2 and 67 percent methane (as CO_2eq). Third, the following table shows how these distributions result in emissions to make up the 25,000 tonnes/year threshold in the Methane Tax.

Emissions Producing 25,000 tonnes/year				
CO_2 Emissions	Methane Emissions (CO_2eq)	Methane Emissions (21 GWP)	Methane Emissions (25 GWP)	Methane Emissions (28 GWP)
Natural Gas Production (tonnes/year)				
2187	22813	1086	913	815
Oil Production (tonnes/year)				
8188	16812	801	672	600

This table shows the mass of methane emissions based on three methane Global Warming Potentials (GWP) -- 21 (2010 GWP), 25 (the current GWP) and 28 (EPA's proposed revision to the GWP). In this discussion, it is assumed that EPA will finalize its proposed GWP revision and change the methane GWP to 28. Fourth, when EPA proposed its Subpart OOOOb and OOOOc regulations in 2021, it set a threshold for its Leak Detection and Repair (LDAR) program of 3 tons/year (2.722 tonnes/year) from a well site. This can be considered as a proxy for a marginal well.

Using this information, a small business well producer with operations across an AAPG basis would be subject to the Methane Tax threshold with as few as 220 oil wells or 300 natural gas wells. These totals are well within the operations of a typical small producer. Clearly, this application violates the Congressional intent to exclude small businesses and marginal wells from the scope of the Methane Tax.

2. *EPA's proposed approach to a WEC applicable facility egregiously worsens the impact on small producers that own Gathering and Boosting operations*

As adverse as the Subpart W facility definition is for small producers, EPA would make it extraordinarily harsher if the producer operates Gathering and Boosting. First, the Gathering and Boosting (G&B) Emissions Factors (EF) under Subpart W for methane emissions are based on mileage of pipe, not on actual emissions. Second, the WEC emissions threshold for G&B is one quarter of the threshold for natural gas production. Third, EPA is proposing that production (oil and natural gas) and G&B be treated as one applicable facility under the Methane Tax. Under this approach, which will be discussed in more detail below, using the EF in EPA's proposed Subpart W revisions, a small producer with as little as 560 miles of unprotected pipe in an AAPG region would equate to the 300 marginal natural gas wells described above and thereby pull that producer into the Methane Tax.

3. *EPA fails to properly address the accuracy of the emissions factors it was mandated to improve under the Methane Tax.*

As stated above, IPAA has previously addressed its concerns about EPA's actions to fulfill its mandate under the Methane Tax to revise Subpart W. While those comments present a more extensive view, a key aspect is restated here:

> EPA actions to revise component emissions factors raise serious questions about both the approach and the proposal. As discussed above, the Inflation Reduction Act mandate to revise Subpart W requires EPA to conduct thorough analyses of the numerous emissions factors and either independently validate them or develop its own valid factors. It failed to do either.
>
> Instead, it turned to three reports as the basis for new emissions factors. These reports are generally referenced as Zimmerle[1], Pacsi[2] and Rutherford[3].
>
> However, EPA's use of these materials demonstrates a callous disregard for the mandate EPA must meet in revising Subpart W. The Zimmerle report addresses emissions from gathering compressor stations; the Pacsi report addresses emissions from oil and natural gas production equipment leaks. Each of these studies conclude that the current emissions factor calculation process under Subpart W overstates emissions that they studied. The Zimmerle report states:
>
>> Combining study emission data with 2017 GHGRP activity data, the study indicated statistically lower national emissions of … 66% … of current GHGI estimates, despite estimating 17% … more stations than the 2017 GHGI ….
>
> The Pacsi report states:
>
>> The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22% to 36% for the sites surveyed in this study as compared to direct measurements of leaking components because of a lower frequency of leaking components in this work than during the field

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[1] Zimmerle, D., et al. "Methane Emissions from Gathering Compressor stations in the U.S." Environmental Science & Technology 2020, 54(12), 7552-7561, available at https://doi.org/10.1021/acs.est.0c00516.

[2] Pacsi, A. P., et al. "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." Elem Sci Anth, 7: 29, available at https://doi.org/10.1525/elementa.368. 2019

[3] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. et al. Closing the methane gap in US oil and natural gas production inventories. Nat Commun 12, 4715 (2021). https://doi.org/10.1038/s41467-021-25017-4

> surveys conducted more than 20 years ago to develop the current EPA factors.

To show the EPA lack of regard for its mandate, EPA ignores these conclusions and cherry picks elements of the reports to increase the component emissions factors in Subpart W. The Rutherford study takes a different approach. It makes the assumption that component based emissions estimates understate actual emissions because it believes that ambient monitoring presents more accurate results. Consequently, it surveys a variety of component based emissions studies to create emissions factors higher than those in the current Subpart W and adopts them as more accurate.

Critically, EPA embraces all these various changes that increase the Subpart W emissions factors, but it never attempts to independently validate them. The effect of this action is increases in virtually every component emissions factor, some of which would yield emissions estimates 5 times or more than the current Subpart W calculations. Not only is this approach a clear dereliction of EPA's responsibilities, but it also has the effect (along with changing the GWP for methane) of de facto lowering the 25,000 mt/year threshold and raising the emissions subject to methane tax. Enverus Intelligence Research, a subsidiary of the energy-focused Software as a Service firm Enverus, has found the proposed regulations would more than double 2021 reported methane and increase overall carbon dioxide-equivalent emissions by 41%. If EPA is intentionally revising the Congressionally enacted methane tax through its rulemaking actions, it should be held to a standard that requires it prove that its revisions are valid.

B. Waste Emissions Charge

Because the Methane Tax contains no legislative history and frequently fails to truly define its terms, EPA must interpret the legislative text. In its proposal EPA frequently refers to terms like "a plain reading" of the statute. However, EPA manipulates its reading of the text by only partially reading the text or ignoring key terms. As a result, it creates inappropriate conclusions and therefore inappropriate regulatory proposals.

Definition of Applicable Facility

As described previously, EPA fails to address the inappropriate use of the GHGRP Subpart W facility definition in the Methane Tax – a definition that EPA characterized by describing as follows:

> These definitions are intended only for purposes of subpart W and are not intended to affect to definition of a facility as it might be applied in any other context of the Clean Air Act.

But, in the definition of "applicable facility", EPA proposes a definition that compounds this misuse outrageously. EPA proposes that:

> In cases where a subpart W facility reports under two or more of the industry segments listed in the previous paragraph, the EPA proposes that the 25,000 mt CO2e threshold would be evaluated based on the total facility GHG emissions

reported to subpart W across all of the industry segments (i.e., the facility's total subpart W GHGs).

This proposal appears to create a structure that would compel operators to sum emissions of their operations in an AAPG basin to include, for example, their oil and natural gas production operations and their G&B operations such that if both were below 25,000 mt/year but the sum were above 25,000 mt/year, their operations would then become subject to the WEC. This proposal extends an already inappropriate approach to a facility definition to arbitrarily capture even more operations for what is solely intended to make them subject to the Methane Tax. It should be summarily rejected.

Calculations of WEC Emissions Thresholds

1. *EPA fails to use natural gas when the term is in the text of the statute.*

A key and clear failure in EPA's interpretation of the legislative text is its failure to use natural gas as the basis of WEC thresholds when the term is in the text. This failure results in EPA effectively raising the WEC emissions threshold by about 30 percent. Most of the WEC emissions thresholds are based on natural gas sales or throughput. This discussion will focus on the emissions threshold for the onshore petroleum and natural gas production industry segment that sends natural gas to sales. EPA presents this calculation as follows:

$$TH_{is,Prod} = 0.002 \times \rho_{CH4} \times Q_{ng,Prod} \qquad \text{(Eq. B-1)}$$

Where:

$TH_{is,Prod}$ = The methane waste emissions threshold for the industry segment at a WEC applicable facility for the reporting year in the production sector that has natural gas sent to sale, metric tons (mt) CH_4.

0.002 = Industry segment-specific methane intensity threshold, as specified in CAA section 136(f), for methane emissions for applicable facilities with natural gas sales in the production sector, thousand standard cubic feet (Mscf) CH_4 per Mscf of natural gas sent to sale.

ρ_{CH4} = Density of methane = 0.0192 kilograms per standard cubic foot (kg/scf) = 0.0192 metric tons per thousand standard cubic feet (mt/Mscf).

$Q_{ng,Prod}$ = The total quantity of natural gas that is sent to sale from the WEC applicable facility in the reporting year, as reported pursuant to part 98, subpart W of this chapter. For onshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(1)(i)(B) of this chapter, in Mscf. For offshore petroleum and natural gas production, you must use the quantity reported pursuant to proposed § 98.236(aa)(2)(i) of this chapter, in Mscf.

The two key factors in this equation are the use of natural gas sales as the basis of the emissions threshold and the use of methane density to convert volume to mass. Methane is not natural gas.

Natural gas is denser than methane. By using methane density instead of natural gas density, EPA lowers the emissions threshold and effectively raises the Methane Tax payment.

Then, in one of its more disingenuous statements, EPA argues that its use of methane density instead of natural gas density is actually intended to decrease the reporting burden on industry.

> With the exception of production facilities that only produce oil, the statutory text clearly lists natural gas as the throughput value. Further, the proposed approach can be implemented with data currently reported under subpart W, while alternative methane intensity methodologies would require reporting of additional data and increase the burden on the oil and gas industry. ... An approach that calculates methane intensity as the mass of methane emissions divided by the mass of natural gas would require facilities to collect and report detailed information on all of the constituents of natural gas throughput. ... The EPA therefore believes that the proposed approaches not only follow a plain reading of CAA section 136(f) but are also the best and most reasonable approaches.

If EPA really believes in plainly reading the statute, it will clearly conclude that the statute uses natural gas as the basis for the WEC and the emissions threshold. Consequently, its task is to present options to use natural gas density in its calculations.

Certainly, one option should be for operators to provide natural gas density information based on their operations and EPA needs to provide a framework for the submission of such data.

However, other approaches are also available. For example, since 2011, EPA has used a memorandum, "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking" (included as Appendix B in this document) to provide natural gas composition data for its regulations. Using this document, a natural gas density of approximately 0.0535 lb/scf can be calculated. This demonstrates the significance of using a natural gas density rather than the methane density of 0.0416 lb/scf. It is nearly 30 percent higher. Given that EPA has been using this document for its rulemaking for over a decade, it can certainly be used as a default value if no other information is available.

Another approach that EPA could take would be to work with organizations like the Energy Information Administration or the Gas Technology Institute or Enverus that may have databases with AAPG basin average natural gas densities. If such databases do not exist, EPA could initiate an effort by one of these organizations to obtain such information. These densities could then be used as AAPG basin default values when no other information is available.

Any approach to define default natural gas densities and to provide for operator supplied natural gas densities are clearly plausible approaches to address the issue of needing a natural gas density to calculate the emissions threshold.

But what is clear is that EPA's approach of using a methane density is not a valid plain reading of the statute and must be altered.

2. *The current approach is unfair to oil dominated production and must be changed.*

Some of the emissions thresholds in the Methane Tax seem to be derived from various voluntary emissions intensity programs related to natural gas production. At least this appears to be the case for the onshore production emissions threshold for operators with natural gas sales. This emissions intensity target was developed by companies operating production that is dominated by natural gas sales. While it may be a rational target for such operations, it is inappropriate for production that is primarily petroleum with minimal or limited natural gas sales. Similarly, the emissions threshold for petroleum production with no natural gas sales is wholly inconsistent with the threshold for natural gas production facilities and generates a likely impossible target to meet.

The following are some examples of the implications of the emissions thresholds for different operations. For illustrative purposes, they will be based on petroleum production of one million barrels/year. One million barrels per year can be converted to natural gas production based on energy equivalency which is 6 mcf of natural gas is equivalent to one barrel of oil. Therefore, one million barrels of oil is equivalent to 6 million mcf of natural gas.

For petroleum production with no gas sales, the Methane Tax emissions threshold is 10 metric tons per one million barrels. If this production was natural gas where the emissions threshold is 0.2 percent of natural gas sales, then for 6 million mcf of production (using natural gas density in the calculation), the threshold would be 292 metric tons. This multiple of 29 is wholly inappropriate.

A similar issue exists for a petroleum producer with limited natural gas sales. Assume that the same petroleum producer had an additional one percent of its oil production as natural gas – 60,000 mcf. This would produce a natural gas emissions threshold of about 2.9 mt. Again, a threshold that is wholly inconsistent with a comparable natural gas energy producer.

3. *The G&B emissions threshold has no identifiable basis and is inequitable*

There is nothing in the Methane Tax that explains why the emissions threshold for G&B was selected. It is well below the emissions threshold for other segments of the industry. This low threshold is complicated by the egregious use of the Subpart W EF for G&B. As noted above, the G&B EF are based on miles of pipe and do not reflect control measures or emissions data that could show dramatically different emissions profiles. EPA needs to justify the G&B emissions threshold and generate valid EF for this sector.

Compliance Date for the Submission of Methane Tax Payments

EPA's proposed approach for the payments of the Methane Tax is unjustified and flies in the face of historic filing issues with the GHGRP. For the many years that the GHGRP has been in operation, the filing date has been March 31 of the year following the year of emissions reporting (e.g., March 2024 for 2023 data). However, given the short time frame to develop the data, verification of data has extended into November in many instances.

Now, EPA is proposing that the WEC filing and payment must be submitted on March 31. It allows modifications to the WEC filing to be made until November 1. However, while any reductions in emissions would allow for a rebate, increases would have penalties applied to them. This approach is unnecessary. Given the history of the GHGRP, EPA knows there will likely be modifications needed for many filings. Consequently, a fair approach would delay the payment date until November 1, after the revisions and verifications have been completed.

Regulatory Compliance Exemption

IPAA has doubted that the Regulatory Compliance Exemption (Exemption) would be realistically available; it has always appeared a false promise. Consistent with this perception, EPA's proposal demonstrates that it will use every measure possible to prevent the application of the Exemption.

1. *The Exemption Proposal is Inconsistent with the Plain Reading of the Statute*

To begin with, EPA shows its bias by choosing to cleverly try to parse the language of the statute and make it as unworkable as it can. Its first act is to misread the following language:

> ...methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities.

EPA chooses to focus on the term "all States" in isolation from the reference to "applicable facilities". A clear plain reading of the statute would reflect Congress' already punitive limitation on companies that would prevent them from using the Exemption as soon as a state in which they operate has plans in place by requiring that all the states where they had applicable facilities have approved section 111(b) and section 111(d) plans in place. That is, if a company had applicable facilities in Texas and West Virginia, it could not benefit from the Exemption in Texas if West Virginia's plans had not been approved. Both Texas and West Virginia must have approved plans.

EPA drives the issue to an absurd conclusion by interpreting the language to mean that if a company had operations in Texas and West Virginia and both had approved plans, the company could not utilize the Exemption if, say, South Dakota did not have approved plans – a state where it had no applicable facilities.

EPA's rationale for this interpretation can have no purpose other than to prevent the Exemption from being used and compel higher taxes on companies when they are, if fact, acting as the statute would envision – reducing their methane emissions and complying with the regulations.

2. *The Equivalency Proposal is Unfair and Designed to Prevent Use of the Exemption*

The second major task for EPA involving the Exemption relates to determining whether the promulgated Subpart OOOOb regulations and the forthcoming Subpart OOOOc state regulations "will result in equivalent or greater emissions reductions as would be achieved by the [2021] proposed rule…". EPA's course of action here is to punt. EPA merely states it will address this action in a future rulemaking after all the state plans have been approved.

This deferral of action by EPA leaves the entire process in an unacceptable limbo. This decision has always been fraught with confusion and EPA does nothing to create a framework for industry or states as it avoids any action – even when some actions are possible.

At issue here is that not only will this determination affect the Methane Tax, it can influence the state planning process if EPA were to conclude that the Subpart OOOOb regulations failed to meet the equivalency test. If so, it would mean that state plans would have to fill the gap perhaps compelling existing source regulations that are more extreme than those in the EG – or Subpart OOOOb.

Confounding the decision-making process is the fundamental challenge inherent in interpreting the 2021 Subparts OOOOb and OOOOc proposals. The 2021 proposal was largely devoid of true regulatory language, raising the issue of how EPA will evaluate this amorphous proposal. Numerous questions arise. For example:

a. How will EPA interpret the 2021 Subpart OOOOb proposal against the final 2024 Subpart OOOOb regulations? This comparison can be made now since the Subpart OOOOb regulations are final.
b. How will EPA address the 2021 Subpart OOOOc proposal given that the EG process allows states to develop comparable regulations and that the Remaining Useful Life and Other Factors (RULOF) provisions of Section 111(d) can be applied and applied differently in each state? Understanding this framework could potentially significantly affect EPA's conclusion.

EPA's failure to suggest how it will grapple with these complex decisions leaves the regulated community and states in a position of trying to make key regulatory and investment decisions in a void. Also, EPA's failure to address these decisions allows it to prevent applicable facilities from accessing the Exemption by not taking any action. Under the deferral approach, all state plans could be approved, but EPA could just defer the Exemption by making no decision.

There is nothing in the statute that prevents EPA from making segmented determinations on the equivalency of regulatory programs relative to the 2021 proposal. For example, as suggested above, EPA could determine if the final Subpart OOOOb regulations are equivalent to the 2021 Subpart OOOOb proposal. If they are not, it largely closes out the availability of the Exemption. Similarly, state-by-state determinations regarding Subpart OOOOc are feasible with the larger question being how EPA will assess how the 2021 Subpart OOOOc EG would have been implemented when there is virtually no regulatory language available. At least under a state-by-state approach, the potential for the Exemption to be available in a timely manner would be far higher, particularly if EPA junks the current proposal that all states must have approved plans before any applicable facility can utilize the Exemption and returns to a more logical plain reading of the statute that is described above.

EPA's approach in comparing the 2021 proposal to the 2024 final Subpart OOOOc EG would be inappropriate and unfair to the most vulnerable of existing sources. EPA asserts that it would assume that the 2021 EG would be implemented as proposed (although the proposal was not regulatory language). However, it would compare that assessment with the approved state plan that includes RULOF facilities. Such an approach is inequitable. First, there is no reason to assume that the RULOF facilities under the 2024 EG would not have been RULOF facilities under the 2021 proposal since they are clearly facilities where the regulations pose such a severe burden that they qualify as RULOF facilities. Second, penalizing all applicable facilities in a state because it has RULOF facilities is completely unwarranted and inequitable. Third, if the impact of the approach is to deny facilities that deserve RULOF treatment its application in order to obtain the Exemption for the remaining facilities in a state is an egregiously harsh punishment for those uneconomic facilities that are likely mature operations and probably small businesses. Therefore, a more equitable approach would compare whatever EPA concludes in the efficacy of the 2021 EG proposal with the basic regulatory structure in an approved state plan under the 2024 EG.

3. *Actual Noncompliance Needs to be the Basis for Denying an Exemption*

The third key ingredient to obtaining the Exemption is compliance with the Subpart OOOO family of regulations and state plans implementing the EG. Here, again, EPA proposes an approach intended to preclude the use of the Exemption. As EPA describes:

> CAA section 136(f)(6)(A) states that the WEC shall not be imposed "on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111." For the purpose of determining WEC facility eligibility for the regulatory compliance exemption, the EPA proposes that the compliance status of CAA section 111(b) and (d) facilities contained within a WEC applicable facility would be assessed based on compliance with the applicable methane emissions requirements for the Oil & Natural Gas Source Category (40 CFR part 60, subparts OOOOa, OOOOb, and OOOOc).

The statutory language gives EPA wide latitude to determine what constitutes compliance with the federal and state regulations. There is nothing in this language that prohibits EPA from using a test such as substantive compliance which would be appropriate, despite EPA's assertion otherwise.

In fact, to create a fair compliance test, there are several key components that should be included. First, the compliance test should be substantive compliance, not some shallow failure to adhere to some trivial detail. Second, the noncomplying events should be identified as a result of regulatory actions by the appropriate governing regulator. Third, the events should be adjudicated to assure that they are actual noncompliance with fines, penalties or specific performance actions assessed. Fourth, only the applicable facility where the noncompliance occurred should be denied the Exemption; other applicable facilities should not be affected.

Auditing, Compliance and Enforcement

EPA devotes two paragraphs of largely boilerplate material describing its auditing, compliance and enforcement policies. Nothing in them suggests that EPA has any intent not to use these authorities in the harassing fashion that has been the history of its actions related to the American oil and natural gas production industry.

The creation of the Methane Tax gives pervasive and largely unfettered opportunities to use auditing and enforcement actions to adversely affect oil and natural gas producers. EPA can audit any producer, challenging every calculation that is made, or challenging whether a small producer should have filed Subpart W and Methane Tax information. It can threaten large and crippling fines without any standards regarding the development of the information.

IPAA has raised this issue previously because of past experiences with the Office of Enforcement and Compliance Assurance (OECA). OECA's actions to target small businesses with crippling fines generates a harsh adverse dynamic. Since EPA seems intent on using the

Methane Tax to capture small businesses and marginal wells in its scope, EPA needs to determine how it will use these enforcement tools and make those policies public. It has not.

Conclusion

IPAA opposed the Methane Tax when it was being developed. It is clearly a punitive tax, cast as a backstop to the Subpart OOOO family of regulations. It presents itself as necessary to deal with an urgent need to reduce American methane emissions in the context of a global climate challenge; however, it only addresses the thirty percent of American methane emissions from the oil and natural gas industry, leaving the other seventy percent untaxed. That seventy percent is also largely unregulated; certainly, it is not regulated to the extent of oil and natural gas. The Methane Tax exemplifies the worst in legislation – no hearings, no committee reports, no conference report, no statements during floor debate. Now, EPA is using its regulatory authority to interpret the statute to consistently increase the taxable entities, to increase emissions calculations and to increase waste emissions thresholds while limiting the availability of the Exemption. IPAA urges EPA to reverse this course, withdraw this proposal and the Subpart W proposal, and limit the adverse effects of the Methane Tax.

If IPAA can provide further information, please contact Dan Naatz at dnaatz@ipaa.org.

Sincerely,

Dan Naatz

Dan Naatz
Chief Operating Officer and
Executive Vice President

APPENDIX A

IPAA Comments: Greenhouse Gas Reporting Rule: Revisions and Confidentiality
Determinations for Petroleum and Natural Gas Systems
September 30, 2023

INDEPENDENT PETROLEUM
ASSOCIATION OF AMERICA

September 30, 2023

ENVIRONMENTAL PROTECTION AGENCY
40 CFR Part 98
[EPA-HQ-OAR-2023-0234; FRL-10246-01-OAR]
RIN 2060-AV83

Re: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA). IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of American oil and natural gas wells, produce 83 percent of American oil and produce 90 percent of American natural gas.

In addition to the specific comments made herein, IPAA has joined comments submitted separately by the American Petroleum Institute (API).

These comments address proposals by the Environmental Protection Agency (EPA) to revise reporting requirements for Petroleum and Natural Gas Systems for the Greenhouse Gas Reporting Program (GHGRP) under Subpart W.

Subpart W Mandate

Initial efforts to revise Subpart W were included in 2022 as a part of a similarly titled proposal – Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Docket No. EPA-HQ-OAR-2019-0424. However, enactment of the Inflation Reduction Act (IRA) mandated that EPA revise Subpart W because of its use as the emissions basis for inclusion in and the calculation of the Methane Emissions Reduction Program (MERP) methane tax. In fact, no action taken now to revise Subpart W cannot be evaluated without considering and understanding its implications under the methane tax.

The mandate to revise Subpart W is no small task. The history of Subpart W demonstrates that its accuracy was never intended to be the basis for use as a taxing mechanism. Generally, its emissions factors were developed from limited emissions studies that were never structured to develop precise emissions estimates. The Inflation Reduction Act mandate requires EPA to:

> Not later than 2 years after August 16, 2022, the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under

> subsections (e)[1] and (f)[2] of this section, are based on empirical data, including data collected pursuant to subsection (a)(4)[3], accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c)[4] is owed.

The current proposal fails to remotely meet this mandate regarding either time or substance.

One obvious element of the MERP is that its timelines for action are completely inconsistent with reality. It initiates the methane tax in 2025 based on 2024 emissions reporting while falsely promising that compliance with federal Subpart OOOO, OOOOa, OOOOb, and OOOOc regulations and emissions guidelines will void the tax when these regulations will not be fully implemented until at least 2028. Regarding the Subpart W revisions, it requires EPA to finish its revisions by August 2024. The scope of actions that must be undertaken for the full revision of Subpart W, as described in the Inflation Reduction Act, cannot be completed in a two-year window. However, rather than execute its mandated task, EPA proposes a thinly disguised cosmetic rework of the same material that has existed for years with little or no validation by EPA – and, even then, EPA does not apply its changes for a year after its mandated deadline.

If Congress intends to impose millions of dollars of taxes on methane emissions from the petroleum and natural gas industries, potentially crippling the production of millions of barrels and cubic feet of these American products, its mandate to EPA to revise the appallingly inaccurate emissions tools of Subpart W must be read as a serious and thorough methodological effort.

Such an effort would have several key elements. First, it must recognize the nature of emissions particularly from petroleum and natural gas production and production related emissions. Second, it must recognize that some emissions can be measured and others will continue to need emissions estimates from factors; these decisions will be particularly influenced by the economic status of the facility operator. Third, it must recognize that EPA will need to validate these measurement tools and the emissions factors.

Emissions from petroleum and natural gas systems are characterized by leaks from pieces of equipment that cannot be readily or continuously measured. They differ by an array of numerous factors – crude oil versus natural gas, associated gas or low volatility crude, wet or dry gas wells. All wells decline as they produce, changing the volume and composition of their production. Studies have shown that low production wells differ from high volume wells. The economics of production differs between high and low production wells, frequently an indication of the capitalization of the operations. The amount of active equipment at a facility changes with production. Some facilities have gathering and compression equipment on site; others do not. Many low production wells do not operate daily. Many small natural gas wells have booster compressors to suck natural gas from the well bore. Emissions analyses show that 90 percent of

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[1] Emissions charge amount

[2] Waste emissions threshold

[3] Direct and indirect costs required to administer this section, prepare inventories, gather empirical data, and track emissions

[4] Waste emissions charge

emissions come from about 10 percent of facilities, with storage tanks and some pneumatic controllers accounting for the predominant percentage of these emissions.

Because so many of the potential emissions sources from petroleum and natural gas production facilities are diverse components like valves, flanges, storage tanks, connectors, and controllers that are individually small, there are not straightforward methods to routinely monitor these emissions. Studies that have been conducted have used methods like bagging equipment to collect emissions for a short period of time. This technique is infeasible for routine operations. Newer facilities with higher volumes of production and more equipment at a site have been able to collect emissions from equipment like pneumatic controllers and pneumatic pumps and route them to vapor capture or combustion. However, such technology is limited if not impossible for older, low production facilities. Consequently, while EPA has been directed to expand the use of actual facility-based emissions data to quantify emissions, there will continue to be a certain need for emissions factors for emissions that are too difficult to measure or too expensive to collect for low production operations.

Perhaps most importantly for EPA and where EPA has failed most clearly in this proposal is the need to produce validated emissions calculations and validated emissions factors for Subpart W. Subpart W presents a long history of relying on limited studies from the 1990s appended using questionable analyses by environmental lobbyists to produce reports on petroleum and natural gas production facilities. Many of these same analyses have been used for the development of EPA methane regulations in Subpart OOOO, OOOOa, OOOOb and OOOOc. Missing from all these EPA actions is careful, thorough validation of the analyses by EPA and replication of these analyses. Many of these studies have been based on a small number of facilities, based on drive-by analysis with no information on facilities' operation, based on recalibrating data in different ways without any new information, based on applying statistical manipulation to produce headline grabbing allegations. Congress' mandate to EPA is connected to very real methane tax consequences. EPA cannot meet this mandate without collecting and analyzing its own data to develop sound, robust emissions calculation methods and emissions factors. This proposal fails completely to meet this essential test.

These challenges for EPA to meet its Subpart W mandate demonstrate clearly that it cannot be done properly in the two-year window of the MERP timeline. For EPA to do it job right, it needs to get changes made to the Inflation Reduction Act to make its timelines for both Subpart W and the completion and implementation of the Subpart OOOOb regulations and OOOOc emissions guidelines to complete these actions before collecting methane taxes from American producers.

New Implications of Subpart W

When Subpart W was solely related to filing under the GHGRP, determining whether a facility needed to file and the accuracy of submitted information carried limited further scrutiny. However, because the MERP imposes a methane tax, all filing decisions now become auditable and subject to penalties under the enforcement provisions of the Clean Air Act (CAA). These new burdens compel EPA to address them in Subpart W, but it does not.

Both the MERP and Subpart W establish a filing threshold of 25,000 mt/year of CO_2eq. This threshold was set initially by EPA when it initiated Subpart W reporting to limit the burden on small businesses while maintaining reporting by the preponderance of emissions sources. It was specifically retained in the MERP legislation. At issue then is the challenge to small producers to determine whether they are subject to the Subpart W filing requirements without compelling them to complete a costly full-blown inventory that is unnecessary. EPA provides no simple estimating procedure to determine whether small producers are near the 25,000 mt/year threshold. Both EPA and Congress have shown that small producers are not the target of the methane tax; however, EPA must now provide a mechanism to easily exclude them without the threat of audit and enforcement by the Office of Enforcement and Compliance Assurance (OECA).

A different, but similar, issue arises for all reporting entities. With Subpart W becoming the basis for the methane tax, any and all information submitted become the subject of audit and enforcement under the CAA. This creates the potential for frivolous and harassing actions by OECA. The history of OECA interaction with American petroleum and natural gas producers has been characterized by OECA actions to target smaller producers with fine threats that would bankrupt them. These actions have included interpretations of regulations by OECA that differed from the interpretation and guidance from the regulatory authors within EPA. Filing under Subpart W creates hundreds of thousands of opportunities to challenge any submitted information. Since EPA has proposed numerous different approaches to submitting information and creates the opportunity for reporters to submit facility specific information, EPA must now assure that good faith actions by reporters are not windows of opportunity for OECA to pursue harassing actions. However, EPA has not provided clear and straightforward guidance in this Subpart W proposal. Nor has it shown that OECA will use such guidance.

Property Transfer

When property transfers, the reporting of emissions takes on a different context because of the introduction of the methane tax. Previously, these issues have been largely related to assuring that there was a source responsible for assuring emissions were reported. The methane tax changes the process because substantial amounts of money are involved and there are equities that need addressed. Essentially, no new owner should be responsible for the methane taxes generated by the prior owner. This EPA proposal regarding the transfer of property fails to set forth clear delineations to create the equity that is essential.

Facility Definition

When EPA set its facility definition for the GHGRP, it was based on the 25,000 mt/year on information indicating that it would exclude small wells and producers. However, experience is showing that the current structure of the definition is capturing facilities comprised of low production wells and gathering and boosting facilities (that were not part of the original threshold selection). EPA is now proposing that emissions calculations be made at the well pad level. It should also revise the facility definition to exclude low production wells and to alter the gathering and boosting calculation to limit the use of arbitrary emissions estimates based on pipeline mileage.

Specific Proposals

EPA actions to revise component emissions factors raise serious questions about both the approach and the proposal. As discussed above, the Inflation Reduction Act mandate to revise Subpart W requires EPA to conduct thorough analyses of the numerous emissions factors and either independently validate them or develop its own valid factors. It failed to do either.

Instead, it turned to three reports as the basis for new emissions factors. These reports are generally referenced as Zimmerle[5], Pacsi[6] and Rutherford[7].

However, EPA's use of these materials demonstrates a callous disregard for the mandate EPA must meet in revising Subpart W. The Zimmerle report addresses emissions from gathering compressor stations; the Pacsi report addresses emissions from oil and natural gas production equipment leaks. Each of these studies conclude that the current emissions factor calculation process under Subpart W overstates emissions that they studied. The Zimmerle report states:

> Combining study emission data with 2017 GHGRP activity data, the study indicated statistically lower national emissions of … 66% … of current GHGI estimates, despite estimating 17% … more stations than the 2017 GHGI ….

The Pacsi report states:

> The most common EPA estimation method for greenhouse gas emission reporting for equipment leaks, which is based on major site equipment counts and population-average component emission factors, would have overestimated equipment leak emissions by 22% to 36% for the sites surveyed in this study as compared to direct measurements of leaking components because of a lower frequency of leaking components in this work than during the field surveys conducted more than 20 years ago to develop the current EPA factors.

To show the EPA lack of regard for its mandate, EPA ignores these conclusions and cherry picks elements of the reports to increase the component emissions factors in Subpart W. The Rutherford study takes a different approach. It makes the assumption that component based emissions estimates understate actual emissions because it believes that ambient monitoring presents more accurate results. Consequently, it surveys a variety of component based emissions studies to create emissions factors higher than those in the current Subpart W and adopts them as more accurate.

Critically, EPA embraces all these various changes that increase the Subpart W emissions factors, but it never attempts to independently validate them. The effect of this action is increases in virtually every component emissions factor, some of which would yield emissions estimates 5 times or more than the current Subpart W calculations. Not only is this approach a clear dereliction of EPA's responsibilities, but it also has the effect (along with changing the GWP for methane) of de facto lowering the 25,000 mt/year threshold and raising the emissions subject to methane tax. Enverus Intelligence Research, a subsidiary of the energy-focused Software as a Service firm Enverus, has found the proposed regulations would more than double 2021 reported methane and increase overall carbon dioxide-equivalent emissions by 41%. If EPA is intentionally revising the Congressionally enacted methane tax through its rulemaking actions, it should be held to a standard that requires it prove that its revisions are valid.

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[5] Zimmerle, D., *et al.* "Methane Emissions from Gathering Compressor stations in the U.S." *Environmental Science & Technology* 2020, 54(12), 7552-7561, available at *https://doi.org/10.1021/acs.est.0c00516*.

[6] Pacsi, A. P., *et al.* "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States." *Elem Sci Anth*, 7: 29, available at *https://doi.org/10.1525/elementa.368*. 2019

[7] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al. Closing the methane gap in US oil and natural gas production inventories*. Nat Commun 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4*

Intermittent Pneumatic Controllers

EPA is proposing a series of different emissions calculations for intermittent pneumatic controllers – one of the largest emissions sources at production facilities based on the current EF. While using more accurate analysis is highly desirable, these proposals have not been independently verified by EPA. Additionally, this approach requires much higher data acquisition for each controller which could be burdensome for smaller companies. At the same time EPA eliminates the EF for intermittent pneumatic controller rather than modify what has clearly been a flawed EF.

Each EF carries with it a history of its development and evolution. Intermittent pneumatic controllers used in oil and natural gas production have been an example of the challenge of developing accurate information. Intermittent pneumatic controllers operate only when they activate. Correspondingly, they emit when they activate unless they are failing for some reason. Intermittent pneumatic controllers are one of the most pervasive pieces of equipment at oil and natural gas production facilities. Consequently, they are one of the largest emissions sources for these operations. At issue is the validity of the EF and the proposed revisions for this equipment.

To illustrate the issue, EPA need look no farther than its own proposed GHGRP revisions for calculating emissions associated with intermittent-bleed pneumatic devices, both those from the 2022 proposed rule (Docket ID No. EPA-HQ-OAR-2019-0424) and those from the 2023 proposed rule that is the focus of these comments (Docket ID No. EPA–HQ–OAR–2023–0234; FRL–10246–01–OAR). The first obvious observation is that the EPA cannot itself decide how to accurately calculate emissions from pneumatic devices, as evidenced by the widely varying proposed revisions.

The current GHGRP - Subpart W rules require reporters to calculate emissions from intermittent-bleed pneumatic devices by:

Utilizing Equation "W-1", where

- EF_t = 13.5 scf/hr/component for intermittent-bleed pneumatic device vents (from Table W-1A), and
- T_t = Average estimated number of hours in the operating year the devices, of each type "t", were operational using engineering estimates based on best available data. Default is 8,760 hours. (every hour of every day in a year)

In the 2022 Proposed GHGRP – Subpart W revisions for calculating emissions from intermittent-bleed pneumatic devices, the EPA proposal allowed one of two calculation methods:

- Utilize Equation "W-1A", where
- EFt = 8.8 scf/hr/component for intermittent-bleed pneumatic device vents (from Table W-1A), and
- Tt = Average estimated number of hours in the operating year the devices, of each type "t", were in service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours (every hour of every day in a year). **This represents a nearly 35% reduction compared to the current emissions factor**,

OR

- Utilize Equation “W-1B”, which contemplates an entirely new proposed alternative calculation methodology allowing reporters that perform approved leak surveys (i.e. LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent-bleed pneumatic devices, and
- Proposes an EF of 24.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 0.30 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 98% reduction from the current required EF for intermittent-bleed pneumatic devices.**

And, now in its latest proposed GHGRP – Subpart W revisions for calculating emissions from intermittent-bleed pneumatic devices, the EPA proposal allows one of three calculation methods. Proposed “Calculation Method 3” is most analogous to the alternative method from the 2022 Proposed Rule and allows for the following:

- Utilize Equation “W-1C”, which, similar to the method described above, allows reporters that perform approved leak surveys (i.e., LDAR surveys with OGI cameras) to identify properly operating v. malfunctioning intermittent-bleed pneumatic devices, and
- Proposes an EF of 16.1 scf/hr/component for malfunctioning/leaking devices and specifies the method for determining the amount of time a device was assumed to be leaking, and
- Proposes an EF of 2.82 scf/hr/component for properly operating devices and specifies the method for determining the amount of time a device was assumed to be leaking. **This represents a nearly 80% reduction from the current required EF for intermittent-bleed pneumatic devices.**

Although many Subpart W reporters currently perform OOOOa compliant LDAR surveys utilizing OGI cameras, in-line with the proposed GHGRP revisions, and are able to identify properly operating devices versus malfunctioning devices, the current rules do not allow the data to be used. And, as such, significantly overstates GHG emissions from intermittent-bleed pneumatic devices.

To demonstrate how GHG emissions from intermittent-bleed pneumatic devices are significantly overstated by the current GHGRP Subpart W rules versus EPA’s proposed revisions from both 2022 and 2023, see the hypothetical scenario below:

<table>
<tr><th colspan="2">Comparison of Methane Emissions Associated with Intermittent-Bleed Pneumatic Devices as Determined by Current GHGRP “Eq. W-1” v. 2022 Proposed GHGRP “Eq. W-1A” AND “Eq. W-1B” v. 2023 Proposed GHGRP “Eq. W-1C” (aka “Calculation Method 3”)</th></tr>
<tr><td colspan="2">Assumptions:
– One Subpart W Reporter
– 100 Intermittent-bleed Pneumatic Devices @ 20 Locations
– Performs compliant OGI leak surveys at all 20 locations one-time per annum
– Identifies 10 malfunctioning (i.e. leaking) Devices (10% leak rate)
– Remaining 90 Devices, verified to be operating normally
– Uses default of 8760 hours for device “operating” (current rule) and “In-service” (proposed rule) times
– Produces dry gas with a 98% CH4 Fraction</td></tr>
<tr><td>Current – “Eq. W-1”</td><td>$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1)
100 devices x 13.5 scf/hr/device x 0.98 CH4 % x 8760 hours = 11,589,480 scf CH4 emissions</td></tr>
<tr><td>2022 Proposed – “Eq. W-1A”</td><td>$E_{s,i} = \sum_{t=1}^{3} Count_t * EF_t * GHG_i * T_t$ (Eq. W-1A)
100 devices x 8.8 scf/hr/device x 0.98 CH4 % x 8760 hours = 7,554,624 scf CH4 emissions</td></tr>
<tr><td>2022 Proposed – “Eq. W-1B”</td><td>$E_i = GHG_i * \left[\left(24.1 * \sum_{z=1}^{x} T_z\right) + \left(0.3 * Count * T_{avg}\right)\right]$ (Eq. W-1B)
0.98 CH4 % x [(24.1 scf/hr/device x 10 leaking devices x 8760 hours) + (0.3 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 2,300,726 scf CH4 emissions</td></tr>
<tr><td>2023 Proposed – “Eq. W-1C”</td><td>$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{16.1 \times T_{mal,z} + 2.82 \times (T_{t,z} - T_{mal,z})\} + (2.82 \times Count \times T_{avg})\right]$ (Eq. W-1C)
0.98 CH4 % x [10 leaking devices ((16.1 scf/hr/device x 8760 hours) + (2.82 scf/hr/device (8760 hours – 8760 hours)) + (2.82 scf/hr/device x 90 non-leaking devices x 8760 hours)] = 3,560,975 scf CH4 emissions</td></tr>
<tr><td colspan="2">Summary – In the scenario above, current GHGRP requirements (“Eq. W-1”) overstate methane emissions associated with intermittent-bleed pneumatic devices by approx. 35% compared to 2022 proposed GHGRP alternative 1 (“Eq. W-1A”), by approx. 80% compared to 2022 proposed GHGRP alternative 2 (“Eq. W-1B”) and by approx. 69% compared to 2023 proposed GHGRP Calculation Method 3 (“Eq. W-1C”).</td></tr>
</table>

This example demonstrates that the agency is well aware that current GHGRP rules and associated mandated calculation methodologies significantly overstate emissions for intermittent-bleed pneumatic devices.

IPAA generally supports EPA’s proposal to allow multiple calculation methods for determining emissions from natural gas driven intermittent-bleed pneumatic devices. However, there are concerns with each proposed method as described below:

Calculation Method 1 – Direct measurement with flow monitoring device

This calculation method as an alternative for reporters that have or can cost-effectively install flow monitoring devices to directly measure fuel gas supplied to intermittent-bleed pneumatic devices. For many, if not most, reporters that do not already have flow monitoring devices installed, it will be cost prohibitive to install these devices and currently this is the only proposed method that fully allows the use of "empirical data" as mandated by the IRA. Consequently, EPA should amend calculation Methods 2 & 3 as described below.

Calculation Method 2 – Direct measurement of device vent rates and use of "In-service" times

This proposed calculation method allows reporters to use empirical data in the form of direct measurement to determine vent rates from intermittent-bleed pneumatic devices. Unfortunately, this method, as proposed, is only a half-solution, in-terms of allowing empirical data, because it still requires reporters to use the non-empirical factor of "in-service (i.e., supplied with natural gas)" hours to calculate emissions.

Under proposed Calculation Method 2, reporters are required to determine emissions using the actual "number of hours the pneumatic device was in-service (i.e., supplied with natural gas) in the calendar year" for devices where vent rates were measured AND to use proposed "Eq. W-1B" for devices that did not have vent rates directly measured during the calendar year. Variable "T_t" in proposed Eq. W-1B, requires reporters to determine the "Average estimated number of hours in the operating year the devices of each type "t", were in-service (i.e., supplied with natural gas) using engineering estimates based on best available data. Default is 8,760 hours." In both instances the requirement to determine emissions based on the concept of "in-service" hours completely contradicts the IRA mandate to allow the use of "empirical data."

Interestingly, EPA proposes that, absent any measured volume during a 5-minute or 15-minute sampling period, as applicable, reporters can use "company records or engineering estimates" to estimate per actuation emissions and actuation cycle counts to estimate emissions. See the proposed rule excerpt below:

> For intermittent bleed devices, the lack of any emissions during a 5-minute or 15-minute period, as applicable, would indicate that the device did not actuate and that the device is seating correctly when not actuating. As such, we are proposing that engineering calculations would be made to estimate emissions per activation and that company records or engineering estimates would be used to assess the number of actuations per year to calculate the emissions from that device for the reporting year." (FR p. 50311)

This approach represents "empirical data" consistent with the IRA mandate and would yield more accurate emissions estimates for intermittent-bleed pneumatic devices. As such, EPA should amend the Calculation Methods 2 & 3 to allow the use of this approach more broadly, in lieu of the "In-service" hours concept and not only when there is a lack of emissions measured during a sampling period, but in all cases.

Under proposed Calculation Method 2, EPA proposes to require the vent rate for every pneumatic device to be directly measured every 5 years. This measurement frequency is overly burdensome and unnecessary to determine a statistically representative average vent rate for devices of the same type (i.e., intermittent bleed). EPA should amend the proposed rule to only require 10% of devices to be surveyed each year.

Further, under proposed Calculation Method 2, EPA proposes to require a 15-minute vent rate sampling period for each pneumatic device, except isolation valve actuators, which would only be required to be sampled for a minimum of 5 minutes. See excerpt below:

> We are proposing a reduced monitoring duration for isolation valve actuators specifically because these devices actuate very infrequently, and the monitoring is targeted to confirm the valve actuators are not malfunctioning (i.e., emitting when not actuating) rather than to develop an average emission rate considering some limited number of actuations." (FR p. 50311)

A reduced monitoring frequency of only 5 minutes is adequate to confirm a pneumatic device is not malfunctioning. It is not only true for isolation valve actuators, but for all intermittent bleed pneumatic devices. Accordingly, EPA should amend the proposed rule to only require a 5-minute sampling period for all devices. The currently proposed 15-minute sampling period is overly burdensome and unnecessary to accurately estimate emissions.

Calculation Method 3 – Intermittent-bleed Pneumatic Device Surveys

As EPA acknowledges in its proposed revisions to the GHGRP rule, it is possible to identify and distinguish malfunctioning or "leaking" intermittent-bleed pneumatic devices from properly operating intermittent-bleed pneumatic devices via leak surveys (see below).

> As part of our review to characterize pneumatic device emissions, we found a significant difference in the emissions from intermittent bleed pneumatic devices that appeared to be functioning as intended (short, small releases during device actuation) and those that appeared to be malfunctioning (continuously emitting or exhibiting large or prolonged releases upon actuation). For natural gas intermittent bleed pneumatic devices, it is possible to identify malfunctioning devices through routine monitoring using optical gas imaging (OGI) or other technologies.
> (FR 50312)

This alternative method for calculating emissions from intermittent bleed pneumatic devices should be included for reporters that are unable to justify the costs associated with proposed calculation Methods 1 & 2, even though it does not allow the use of empirical data.

However, proposed calculation Method 3, in its current form, like the current Subpart W rules, will still likely overstate emissions from intermittent bleed pneumatic devices significantly, because it continues to rely upon the use of one-size fits all leaker emissions factors and a determination of "in-service" hours based on a default of 8760 hours (every hour of every day in a reporting year). This approach, even though properly operating devices are confirmed via approved leak surveys, requires reporters to assume properly operating intermittent bleed pneumatic devices are leaking continuously or nearly continuously.

Properly operating intermittent bleed pneumatic devices, as acknowledged by the agency, do not vent continuously. By design and definition, intermittent-bleed pneumatic devices only vent ("process emissions") when they actuate. Therefore, EPA should amend Calculation Methods 3 to allow reporters to use "company records or engineering estimates" to determine actuation cycle counts, when the data is available, in lieu of the "In-service" hours concept. This approach would allow the use of "empirical data" and yield more accurate emissions estimates.

The currently proposed EFs for Calculation Method 3 vary significantly from the 2022 proposed rule, see table below, without sufficient basis. From available information, it appears that EPA used the Zimmerle study to develop its 2023 proposal. However, these values are based on controllers under very different operating conditions than those in the oil and natural gas production component of the industry. Experts who have evaluated the 2023 proposal conclude that the 2022 factors are more appropriate. EPA should amend the proposed leaker factors to align with the 2022 proposed rule, which was consistent with the "API Field Measurement Study: Pneumatic Controllers" (Tupper 2019)

	Whole Gas EF – Properly Operating Intermittent Bleed Pneumatic Device	Whole Gas EF – Malfunctioning Intermittent Bleed Pneumatic Device
2022 Proposed Rule	0.03 scf/hr/device	24.1 scf/hr/device
2023 Proposed Rule	2.82 scf/hr/device	16.1 scf/hr/device

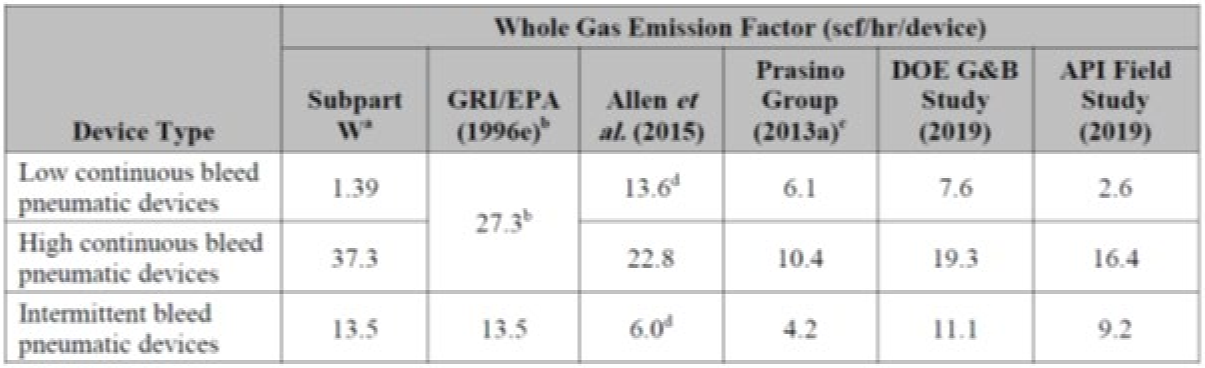
Retain a Calculation Method Similar to the Current Subpart W Regulations

EPA should allow a fourth calculation method similar to the method in the current Subpart W rules and that which was included in the 2022 proposed rule, that allows small operators to use a single whole gas emissions factor-based approach for calculating emissions from intermittent-bleed pneumatic devices. EPA suggests that such an alternative is unnecessary because of the Subpart OOOOb and OOOOc proposals. However, neither of those are finalized and alternative approaches to managing emissions have been proposed. In particular, the Subpart OOOOc Emissions Guidelines are not binding on states and state regulations may continue to allow natural gas driven pneumatic controllers.

The current EF for intermittent pneumatic controllers is 13.5 scf/hour/component. This EF was developed in the mid-1990s based on data collected from 19 controllers. It is hardly an example of robust data acquisition. Since then, the validity of this EF has been consistently questioned. It has become a higher profile issue as various environmental lobbying groups have produced reports based on the GHGI that is largely developed using the GHGRP.

Over the years other studies have been done to address this EF. However, the quality of EPA's 2022 analysis of this EF that has been such a target is wanting. In general, EPA discusses six studies that have been done with information on intermittent pneumatic controllers for production operations (GRI/EPA 1996, Allen, Thoma, Prasino, OIPA and API 2019). Additionally, EPA assessed a Department of Energy study on Gathering and Boosting operations (DOE G&B). In each case EPA discusses the limitations of the studies – short sampling times with assumptions about the activation period for intermittent controllers, emissions that are calculated rather than measured, and classification issues. Then, EPA eliminates two studies (Thoma, OIPA) apparently because of their use calculated emissions (which were far lower than some of the other studies). Subsequently, it produced the following summary table:

Table 2-9. Comparison of Population Emission Factors for Natural Gas Pneumatic Device Venting for Production and G&B Industry Segments



Device Type	Whole Gas Emission Factor (scf/hr/device)					
	Subpart W[a]	GRI/EPA (1996e)[b]	Allen *et al.* (2015)	Prasino Group (2013a)[c]	DOE G&B Study (2019)	API Field Study (2019)
Low continuous bleed pneumatic devices	1.39	27.3[b]	13.6[d]	6.1	7.6	2.6
High continuous bleed pneumatic devices	37.3		22.8	10.4	19.3	16.4
Intermittent bleed pneumatic devices	13.5	13.5	6.0[d]	4.2	11.1	9.2

Next, EPA averaged the intermittent factors for these studies to produce a new EF of 8.8 scf/hr. However, this appears to include the EF from the DOE G&B study; if it had not, the EF would appear to be 8.2 scf/hr. If EPA had included the Thoma and OIPA studies instead of the DOE G&B study, the EF would be 6.8 scf/hr. None of these calculations appear to be weighted based on the number of controllers tested. Consequently, for example, the 19 controllers in the GRI/EPA 1996 study are treated equally with the 128 controllers in the Prasino report. If EPA had weighted the data and used the Thoma and the OIPA studies, the EF would be closer to 3.7 scf/hr/device.

EPA should include a fourth calculation option that provides a single EF and that EF should be 3.7 scf/hr/device.

Gathering and Boosting/Centralized Production Facilities

The Gathering and Boosting category in the methane tax has an inordinately low threshold for its tax basis without any apparent justification. EPA needs to explain the source of the excess emissions fee threshold for gathering and boosting facilities and why it is appropriate. Clearly though only truly separate gathering and boosting operations should be included in it. The current Subpart W proposal creates a critical issue in this regard. The types of equipment used for gathering and boosting of natural gas can be used independently to move natural gas from production facilities to natural gas processing facilities, but it can also be used at oil and natural gas production operations as an integral part of those operations. The proposed Subpart W creates a designation of upstream operators' centralized tank batteries. "Centralized oil production sites" are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well pads". In the proposed rule, EPA has classified centralized oil production sites under the Gathering and Boosting segment. Subpart W needs to be clarified to assure that those centralized oil production operations are included within the reporting for the production facility.

Centralized Oil Production Facility Issues

EPA has recognized centralized production sites as a facility type in the proposed rule and required its emissions to be reported at the site-level, rather than per well ID, which streamlines the reporting for tank batteries. However, there are challenges with including "centralized oil production sites" in the Gathering and Boosting segment.

First, EPA included “production” clearly in the name and it is nonsensical that centralized production sites would be considered part of the Gathering and Boosting segment.

Second, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to “production supportive facilities.” Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment generally results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations (even though consolidation serves to minimize environmental footprint) due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, supportive of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as “associated with a single well pad”, this has created reporting confusion and centralized tank batteries have been categorized differently both by individual owners/operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb regulations, the “centralized oil production facilities” (referred to in NSPS OOOOb as “centralized production facility”) are grouped under the production segment by definition rather than as Gathering and Boosting as explained below.

Currently Subpart W calls and defines the subject facility as:

> “**Centralized oil production site** means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236.”

Meanwhile NSPS OOOOb/OOOOc calls and defines it as:

> “**Centralized production facility** means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.”

In addition, in the Pipeline and Hazardous Material Safety Administration’s (‘PHMSA”) proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate *any* production facilities as “gathering and boosting”. Specifically, as defined in API’s

Recommended Practice-80 and incorporated in 49 CFR 192: "The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. In this context:

> 'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."

Both the NSPS OOOOb/OOOOc and PHMSA's name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. In an effort to mitigate confusion and create more rule alignment, EPA should align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/OOOOc.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal, "as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." Also, even though EPA uses the word "gather" in the definition in OOOOb/OOOOc, these sites are still properly defined as "part of the producing operations."

Further, the fact that EPA has proposed the definition of "centralized production sites" as sites that do not include compressors that are part of the Gathering and Boosting segment is puzzling. If these sites are part of the Gathering and Boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the Gathering and Boosting segment on them? This demonstrates that EPA *does* understand the distinction between gathering and boosting compressors that should appropriately be included in the Gathering and Boosting segment and centralized tank batteries that clearly should not.

As such, EPA should change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb/OOOOc, to align with other federal programs for consistency, and to reflect how the industry owns and operates these facilities. EPA should delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

Further, and most importantly, EPA's proposed definitions are contrary to the MERP waste emissions thresholds, where gathering and boosting sites are considered "non-production". In this language on the Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production". The Gathering and Boosting segment (segment #8) is listed under "Non-Production". Clearly, Congress did not intend for sites associated with production, such as "centralized **production** sites" to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the Gathering and Boosting segment in the past but for application of the tax, these sites should be considered production. Doing otherwise would result in an inequitable application of the tax that would most likely not be applied uniformly by all upstream operators. If EPA does not wish to clear up the confusion and include centralized production sites in the Production segment, EPA should carve out these sites for threshold determination and make these sites subject to the 0.2% threshold as Congress has clearly mandated in the law.

In addition, the categorization of a centralized production site into Gathering and Boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane taxes that may accompany categorizing production sites as Gathering and Boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installations, dramatically increasing the amount of equipment in the field and increasing GHG emissions.

Gathering and Boosting Emissions Factor Issues

A consistent criticism of the current emissions estimation process for gathering and boosting operations relates to its use of emissions factors based on the mileage of pipelines. These factors cannot be altered based on any operational actions other than changing the nature of the pipeline material or structure. These factors from 1996 are unchanged in this proposal despite studies showing that pipeline emissions are overestimated. The consequence of this failure will be to impose the harshest excess emissions tax on this essential component of the natural gas value chain without providing any plausible recourse to alter the emissions calculations. This inaction by EPA flies in the face of its mandate to make the Subpart W emissions estimate more accurate, more reflective of actual operations.

Pipelines are inspected routinely, leaks are fixed, and emissions are eliminated. Only actual emissions should be reported under Subpart W and used for any excess emissions tax calculation; not simply based upon miles of pipeline for which the vast majority are not leaking. There should be an option to demonstrate that emissions are being managed, to show that there are no leaks, or, where leaks are identified, the emissions be based on the leaks found

Pipeline leaks are easily detected through regular inspection using airborne overflights, easement riding and operator inspections. Arguably, these have lower detection limits based on the type of technology used. Larger leaks can easily and quickly be determined by sudden drops in production. The pipeline can be isolated, and the volume of gas lost can easily be determined with great accuracy. Following are some options to determine pipeline factors and credit for inspection:

> Pipeline flyovers have a lower detection limit but do detect methane. If no leaks are found, then no emissions factor should be used for that segment and there should be no excess emissions tax or emissions calculated.
>
> Similarly, when laser-based and acoustic based technology is employed while riding the pipeline easement, leaks are detected. If no leak is detected, then no excess emissions tax or emission factor should be used. If a leak is found, then the actual leak can be measured or an emission factor should be developed. This is currently allowed in the detection of fugitives and a comparable approach for pipelines can be developed.

Use of Advanced Monitoring and Measurement Technologies

For many source categories under Subpart W, EPA has included several options for operators to be able to provide empirical data, such as measurement with metering or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. Some operators have included these technologies in their voluntary methane management programs. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.

Large emissions events

The comments filed by API extensively address the complexity and flaws in the EPA Subpart W proposal on large emissions events. IPAA commends these comments, which it joined in submitting, as a detailed assessment of the issues that need to be resolved.

Flares

The comments filed by API extensively address the complexity and flaws in the EPA Subpart W proposal on emissions issues related to oil and natural gas production flaring. IPAA commends these comments, which it joined in submitting, as a detailed assessment of the issues that need to be resolved.

Environmentalists' Recommendations Inappropriate and Unworkable

As a component of its efforts to suppress American oil and natural gas production, professional environmental lobbying organizations have orchestrated initiatives to press for additions to the Subpart W reporting regulations that are either inappropriate or unworkable. This effort was evident during the August 2023 EPA public hearing on its current Subpart W proposal where about 40 testifiers used exactly the same terms to demand changes to the Subpart W proposal. These demands reflect comments made by the Environmental Defense Fund in several forums regarding Subpart W and the methane tax.

Following is a list of the key demands:

- Integrating top-down, basin-level data alongside site- and equipment-level measurement data. Top-down, basin-level data provides a full picture of total emissions in a region, while site-level, population-based measurement data can provide insights of emissions at a finer resolution, all of which strengthen the accuracy of reported emissions.
- Building in appropriate statistical analysis of measurement data to provide a representative assessment of pollution at the facility and basin levels. Measurement data requires statistical analysis to account for intermittent emission events that may be missed by individual, one-time measurements.
- Defining guardrails and requiring independent verification for self-reported measurements from companies to ensure any company reported data accurately represents operations and is not limited to unrepresentative sites or equipment known to have lower emissions.

One of the key issues here is the relationship between these recommendations and Subpart W. Everyone would like to have the relationship between top-down basin-level data and site- and equipment-level measurement data better understood to resolve the recurring contentious debates regarding these issues. However, such an analysis is well outside the scope of facility reporting under Subpart W. Subpart W is predicated on individual companies reporting emissions estimates based on artificially contrived facilities, e.g., all their operations in an APGA basin. Even if EPA alters the reporting structure to require reporting by well pad, the reporting remains a company-based report. Conversely, basin level data is just that – basin level. It contains information that reflects emissions from numerous well pads, owned and operated by different companies. Moreover, Subpart W information reports annual emissions; top-down basin-level data is temporal in nature perhaps hours, perhaps days, perhaps minutes. No analysis that compares the top-down data and equipment-level measurement data can realistically use Subpart W reporting. These analyses must have a coordinated effort to assess data from both components simultaneously.

Similarly, while statistical analysis can be valuable, it is not in the purview of Subpart W reporting. If EPA wants to conduct appropriate statistical analysis, it must design a more rigorous direct sampling or estimating strategy. Such an effort could be valuable if developed by and validated by EPA. To date, the analyses that have been generated have been thinly veiled advocacy efforts designed to press for regulations so quickly that EPA has never developed a full and accurate understand of the emissions profiles of oil and natural gas production operations.

The final recommendation reflects the environmental lobbying position that only it can be trusted; everyone else must be put to a higher level of scrutiny. The American oil and natural gas production industry is committed to managing its emissions, including methane emissions. It has invested millions of dollars in meeting its requirements and will continue to make necessary investments. While differences may exist regarding the best, most cost-effective actions that should be taken, producers will continue their commitment to protect the environment. Certainly, the idea of having independent verification of self-reported emissions data is appealing. Presently, many of the Subpart W reports are prepared by independent consultants because of the complexity of the current requirements, particularly for smaller producers. The larger issue may well be whether the restructuring of Subpart W reporting in the context of the methane tax will adversely affect access to independent consultants. This issue has arisen in previous EPA NSPS regulations where EPA required professional engineers (PE) to certify information. Two issues arose. First, there were not enough PEs with expertise to undertake the tasks. Second, the license risks for the PE in undertaking the task were too great to bring more into the arena. A similar dynamic may occur in the methane tax context. Because OECA can challenge any reported information and because OECA has a history of using its enforcement power in this industry to target smaller producers, independent contractors may conclude that the risks to their businesses to too high to participate given the magnitude of penalties under the CAA.

Taken as a whole, these environmental lobbying organizations' recommendations are either inappropriate in the context of Subpart W or unworkable or both.

Conclusion

The task mandated to EPA by Congress requires the agency to comprehensively review, revise and validate its Subpart W regulations to make them accurate and reliable because of the role their implementation will play in the MERP, defining exposure and calculating its methane tax. Congress' deadline of EPA's action failed to reflect the reality of the task. EPA, faced with the choice of meeting a deadline or meeting its mandate to comprehensively revise Subpart W, chose the deadline and produced a wholly inadequate compendium of emissions calculations. At its best, the Subpart W proposal collects revisions to the current calculation process that EPA failed to validate as either accurate or appropriate. At its worst, the Subpart W proposal is a thinly disguised effort to raise the MERP methane tax rates through careful selection of higher emissions factors and unworkable calculation procedures. EPA should withdraw the current Subpart W proposal and execute its mandate to make it accurate, including taking the necessary steps to validate the emissions factors or emissions calculation procedures that it ultimately puts in place.

If there are questions or if EPA needs additional information on these comments, please contact Dan Naatz at 202-857-4722 or dnaatz@ipaa.org.

Respectfully submitted,

Dan Naatz
Chief Operating Officer
and Executive Vice President

APPENDIX B

Memorandum to Bruce Moore: Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking

June 2011

E C/R Incorporated *Providing Environmental Technical Support Since 1989*

MEMORANDUM

DATE: July 28, 2011

SUBJECT: Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking

FROM: Heather P. Brown, P.E.

TO: Bruce Moore, EPA/OAQPS/SPPD

The purpose of this memorandum is to document the development of a representative natural gas composition for use in the oil and natural gas sector rulemaking. This composition will be used to determine hazardous air pollutant (HAP) and volatile organic compound (VOC) emissions from several segments of the oil and natural gas sector.

Gas composition data was compiled from several sources across the industry. The following is a list of the sources of data used for this analysis:

- CENRAP database. "Recommendations for Improvements to the CENRAP States' Oil and Gas Emissions Inventory", November 13, 2008. Covers the following States: Texas, Louisiana, Arkansas, Oklahoma, Kansas, Nebraska, Missouri, Iowa, and Minnesota
- GTI Database. "GTI's Gas Resource Database, Second Edition – August 2001"
- TX Barnett Shale. "Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements", January 26, 2009
- INGAA/API Compendium. "Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage Volume 1 – GHG Emission Estimation Methodologies and Procedures" September 28, 2005
- GOADS Offshore. "Year 2005 Gulfwide Emission Inventory Study" December 2007
- NREL LCA. "Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System" September 2000
- Union Gas. Chemical Composition of Natural Gas found online at http://www.uniongas.com/aboutus/aboutng/composition.asp
- Marcellus. "Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program - Well Permit Issuance for Horizontal Drilling And High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs" September 2009
- Wyoming DEQ. Speciation of Natural Gas and Condensate. Courtesy of Cynthia Madison, Wyoming DEQ

Tables 1 and 2 present a summary of the methane, VOC, and HAP contents provided in the above data sources for the production and transmission sectors, respectively, along with an identification of the basins/areas of the country covered by the gas composition.

In addition to the above, gas composition data were collected from the industry in 1995 during the development of the original maximum achievable control technology (MACT) standards for this sector. These data are presented in Tables 3 and 4 for production and transmission, respectively.[1] This 1995 GRI data represents gas samples from across the United States.

Gas Composition for Pneumatics, Equipment Leaks, and Compressors

Tables 1 and 2 also present a comparison of the 1995 GRI data to the other data sources. For production, the 1995 GRI data is well within the ranges of the other data sources which range from 1.19 to 11.6 percent for VOC by volume. The 1995 GRI data is also within the 95 percent confidence interval of the production data which range from 2.81 to 7.82 percent volume for VOC. Of the data sources that provide data on HAP emissions, the GRI data represent gas compositions across the United States, while the CENRAP, TX Barnett, and Marcellus data are specific to the regions specified in Tables 1 and 2. In addition, it can be expected that the gas composition for pneumatic controllers, equipment leaks, and compressors associated with these emissions units are associated with gas from oil wells and gas wells making the range of VOC composition widely varied. Therefore, it was determined that the 1995 GRI data was appropriate to use to develop a representative gas composition for pneumatic controllers, equipment leaks, and compressors.

For the transmission sector, the average 1995 GRI VOC concentration of 0.89 percent volume was compared to other data sources and was found to be in the range of the VOC composition, which ranged from 0.29 to 6.84 percent VOC by volume. It was determined that the 1995 GRI gas composition would be used to represent the average composition of natural gas in the transmission sector, because the other data sources represented natural gas compositions outside the U.S.[i]

The gas compositions from the 1995 GRI data were then converted to weight percents. First, because the average volume percent was not equal to 100, the volume percents were normalized for each component. Then the weight of each component present in the gas was calculated using the molecular weight (MW) for each component in pounds per pound mole (lb/lbmol) and an assumed gas volume of 385 cubic feet (ft^3), which represents one pound mole of gas. Finally, relative weight percents for each component were calculated. These weight percents are presented in Table 5.

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[i] It should be noted that the GRI data contains a statement that the BTEX data are "skewed toward high BTEX and VOC content gases…." However, the 1995 GRI data are within the ranges of the other data and very close to the average of other data identified. Therefore, these data were determined to be appropriate to use to develop a representative gas composition for pneumatics, equipment leaks and compressors.

Table 1. Gas Composition (volume %) for Production Sector

Data Source[a]	Source of Natural Gas	Area Covered	Volume %		
			Methane	VOC	HAP
CENRAP [b]	Conventional Gas Wells	11 Basins: Louisiana Mississippi Salt, Southern Oklahoma, Nemaha Uplift, Arkoma, Cambridge Arch Central Kansas Uplift, Fort Worth, Cherokee Platform, Permian, East TExas, Western Gulf, and Anadarko	87.8	3.50	0.019
GTI Database[c]	Gas Wells	Nationwide, proven reserves, and undiscovered reserves data from 462 basins/formations	82.8	3.61	n/a
INGAA	Unprocessed Natural Gas	Unknown	80.0	5.00	n/a
NREL LCA[d]	Gas Well	Worldwide	65.7	5.66	n/a
MARCELLUS[e]	Gas Well	Marcellus	97.2	2.02	0.03345
WYOMING DEQ[b]	Gas Well	Wyoming	92.4	1.19	0.08
		Minimum	**65.7**	**1.2**	**0.0**
		Maximum	**97.2**	**5.7**	**0.1**
		Average	**84.3**	**3.50**	**0.0**
Gas Composition	Production	Nationwide	83.1	3.66	0.164

n/a = not available

[a] Data from the Barnett Shale database was not speciated and therefore not included in this analysis.

[b] HAP data contains BTEX and n-Hexane

[c] HAP Speciation not provided; hexanes reported as Hexanes Plus

[d] Data provided were ranges for each pollutant (min and max). These values represent normalized averages of these values and may not be valid representations

[e] HAP data only reported for hexane

Table 2. Gas Composition (volume %) for Transmission Sector

Data Source	Source of Natural Gas	Area Covered	Volume %		
			Methane	**VOC**	**HAP**
INGAA	Pipeline Gas	Unknown	91.9	6.84	n/a
GOADS Offshore[a]	Sales Gas	Offshore Gas in the Gulf of Mexico	94.5	1.27	0.099
NREL LCA	Pipeline Gas	Worldwide	94.4	0.90	n/a
Union Gas	Pipeline Gas	United States, Western Canada, and Ontario	95.2	0.29	n/a
	Minimum		**91.9**	**0.3**	**0.099**
	Maximum		**95.2**	**6.8**	**0.099**
	Average		**94.0**	**2.3**	**0.099**
GRI-MACT	Transmission/Unknown	Nationwide	92.7	0.89	0.014

n/a = not available

[a] HAP data contains BTEX and n-Hexane

Table 3. 1995 MACT Correspondence with GRI & EC/R- Production Data

Sector	**Production**											
Site	**GRI1**	**GRI2**	**GRI3**	**GRI4**	**GRI5**	**GRI6**	**GRI7**	**GRI8**	**GRI9**	**GRI10**	**GRI11**	**GRI12**
Mole %												
Nitrogen	2.72	0.44	0.78	0.46	0.79	1.52	1.18	1.74	1.90	1.30	0.52	6.81
Carbon Dioxide	0.04	0.90	0.29	3.37	1.00	0.38	1.67	0.68	0.00	0.47	0.54	8.12
Methane	95.60	93.26	90.62	56.62	80.40	78.38	79.55	74.67	83.90	91.93	88.40	79.83
Ethane	1.04	3.16	4.31	10.87	10.41	10.88	10.40	12.57	7.90	3.80	7.25	2.89
Propane	0.33	1.14	1.90	13.90	4.25	5.41	4.15	5.98	3.86	1.23	1.53	0.94
Butanes	0.16	0.64	1.15	8.59	1.65	2.10	1.74	2.55	1.70	0.70	0.90	0.54
Pentanes	0.07	0.22	0.51	3.61	0.65	0.77	0.69	1.21	0.49	0.24	0.36	0.30
Hexanes+	0.03	0.20	0.37	2.03	0.60	0.36	0.43	0.35	0.17	0.24	0.42	0.52
ppmv												
n-Hexane	88.7	277	664	2783	965	1173	937	2125	517	307	510	681
Isooctane	8.0	31.5	63.5	1552	151	145	112	103	52.0	49.6	32.0	87.0
Benzene	4.9	257	218	328	294	74.4	294	102	57.9	143	617	196
Toluene	2.9	108	117	251	468	92.4	263	31.4	45.6	142	222	213
Ethylbenzene	0	19.7	6.7	27.3	14.5	4.3	3.3	0.8	1.2	11.2	9.0	10.4
m,p-Xylenes	0	34.0	26.6	26.0	87.9	21.7	16.7	1.7	7.3	56.6	45.0	66.0
o-Xylene	0	19.9	5.0	6.2	16.1	3.2	2.4	0.3	0.6	16.9	10.0	16.4

NR = Not Reported

Table 4. 1995 MACT Correspondence with GRI & EC/R (Transmission Data)

Sector	Transmission		Unknown[a]		Transmission	Unknown [a]	Transmission					
Site	GRI13	GRI14	GRI15	GRI16	GRI17	GRI18	GRI19	GRI20	GRI21	GRI22	GRI23	GRI24
Mole %												
Nitrogen	9.89	8.68	2.96	2.55	0.22	1.25	1.16	1.1	1.15	1.12	0.3	1.85
Carbon Dioxide	0.28	0.40	0.58	0.54	0.35	2.62	0.15	0.12	0.07	1.06	1.36	0.66
Methane	81.97	82.61	91.8	92.7	97.4	95.4	98.5	88.2	81.1	94.6	95.8	93
Ethane	6.84	7.06	3.68	3.35	1.94	0.31	0.09	9.69	11.8	2.81	2.03	3.13
Propane	0.78	0.99	0.59	0.52	0.042	0.075	0.005	0.67	3.95	0.155	0.4	0.8
Butanes	0.14	0.17	0.159	0.148	<0.006	0.059	<0.006	0.035	1.189	0.116	0.075	0.314
Pentanes	0.04	0.05	0.045	0.042	<0.003	0.039	<0.003	<0.003	0.341	0.039	0.014	0.132
Hexanes+	0.04	0.03	0.042	0.042	0.004	0.202	<0.002	<0.002	0.226	0.129	0.015	0.103
ppmv												
n-Hexane	63.2	66.9	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Isooctane	17.5	14.5	NR	NR	NR	NR	NR	NR	NR	NR	NR	NR
Benzene	5.0	7.9	51	36	<0.2	471	<0.2	<0.2	10	<0.2	4.5	15
Toluene	5.1	8.1	16	13	<0.1	100	<0.1	<0.1	13	<0.1	3.7	14
Ethylbenzene	0.5	0.6	3	3	<0.1	15	<0.1	<0.1	9	<0.1	0.1	1
m,p-Xylenes [1]	1.4	2.2	12	7	<0.1	11	<0.1	<0.1	1	<0.1	0.6	3
o-Xylene [1]	0.4	0.4										

[1] Sites 15-36 reported only a total xylene result that includes all xylene isomers.

NR = Not Reported

[a] Based on the high methane content (greater than 90 percent) of this datapoint, it was assumed that they were samples from the transmission segment.

Table 4. 1995 MACT Correspondence with GRI & EC/R - Transmission Data (Continued)

Sector	Transmission					Unknown[a]	
Site	GRI25	GRI26	GRI27	GRI28	GRI29	GRI30	GRI31
Mole %							
Nitrogen	1.24	1.75	1.02	1.04	0.49	0.42	0.54
Carbon Dioxide	0.3	0.13	0.44	0.65	1.76	0.87	0.92
Methane	90.2	97.8	96.6	96.1	95.5	96	95.7
Ethane	7.02	0.26	1.78	1.86	1.74	2	2.12
Propane	1	0.014	0.091	0.213	0.351	0.413	0.414
Butanes	0.146	<0.006	0.025	0.06	0.093	0.181	0.175
Pentanes	0.03	0.0015	0.0089	0.0218	0.0354	0.0675	0.0665
Hexanes+	0.021	0.0037	0.0052	0.0219	0.0322	0.073	0.069
ppmv							
n-Hexane	NR	NR	NR	NR	NR	NR	NR
Isooctane	NR	NR	NR	NR	NR	NR	NR
Benzene	9	1.2	0.8	6	7	59	58
Toluene	13	0.4	<0.4	6	6	23	26
Ethylbenzene	<0.3	0.3	<0.1	0.3	0.5	1.8	2
m,p-Xylenes [1]	4	0.2	<0.1	1	1.5	7	5
o-Xylene [1]							

[1] Sites 15-36 reported only a total xylene result that includes all xylene isomers.

NR = Not Reported

[a] Based on the high methane content (greater than 90 percent) of this datapoint, it was assumed that they were samples from the transmission segment.

Table 5. Gas Composition Conversion to Weight Percent

		Production				**Transmission**			
Component	**MW (lb/lbmol)**	**Avg Vol %**[b]	**Normalized Vol %**	**Weight per 385 ft^3 Gas (lbs)**	**Weight %**	**Avg Vol %** [b]	**Normalized Vol %**	**Weight per 385 ft^3 Gas (lbs)**	**Weight %**
Carbon Dioxide	44.01	1.46	1.5%	0.002	3.2%	0.70	0.70%	0.001	1.8%
Nitrogen	28.02	1.68	1.7%	0.001	2.3%	2.04	2.0%	0.001	3.3%
Methane	16.04	82.76	82.9%	0.035	65.7%	92.68	92.8%	0.039	86.2%
Ethane	30.07	7.12	7.1%	0.006	10.6%	3.66	3.7%	0.003	6.4%
Propane	44.09	3.72	3.7%	0.004	8.1%	0.60	0.60%	0.001	1.5%
Butane	58.12	1.87	1.9%	0.003	5.4%	0.16	0.16%	0.000	0.55%
Pentane	72.15	0.76	0.76%	0.001	2.7%	0.05	0.052%	0.000	0.22%
n-Hexane	86.17	0.09	0.092%	0.000	0.39%	0.01	0.0065%	0.000	0.032%
Other hexanes	86.17	0.32	0.32%	0.001	1.4%	0.001	0.00086%	0.000	0.0043%
Isooctane-a	114.23	0.02	0.020%	0.000	0.11%	0.002	0.0016%	0.000	0.011%
Benzene	78.11	0.02	0.022%	0.000	0.083%	0.004	0.0039%	0.000	0.018%
Toluene	92.14	0.02	0.016%	0.000	0.074%	0.001	0.0013%	0.000	0.0070%
Ethylbenzene	106.17	0.001	0.00090%	0.000	0.0047%	0.0002	0.00020%	0.000	0.0012%
Xylene	106.17	0.004	0.0041%	0.000	0.021%	0.0003	0.00030%	0.000	0.0019%
Total		99.85	100.0%	0.053	100.0%	99.91	100.0%	0.045	100.0%

a- Isooctane = 2,2,4, Trimethylpentane

b- Average of all gas compositions presented in Tables 1 and 2 for production and transmission, respectively.

Once the weight percents were calculated for each natural gas component, relative ratios were calculated for methane:total organic compounds (TOC), VOC:TOC, HAP:TOC, VOC:Methane, HAP:Methane, BTEX:Methane, HAP:VOC, and BTEX:VOC. These relative ratios are presented in Table 6.

Natural Gas Composition for Completions and Recompletions

The gas composition for completions and recompletions from gas wells were determined by performing a sensitivity analysis on the compositions of the gas well data using a larger sample size which included data from hydraulically fractured wells. The results of this analysis are shown in Table 7. A mean of 3.63 percent VOC with a 95 percent confidence interval that ranges from 3.30 to 3.96 percent VOC by volume was determined. Based on the summary statistics, these data appear to be reasonable for use in developing an average natural gas composition to use for completions and recompletions of gas wells.

Once it was determined that this data was appropriate, the average gas composition was calculated and then normalized so that the total volume percent equaled 100. This average gas composition is presented in Table 8. The gas composition data was then converted to weight percent by normalizing the volume percent for each component, then calculating the weight of each component using the MW for each component in lb/lbmol and a standard gas volume of 385 ft^3. Finally, relative weight percents for each component were calculated. Once the weight percents were calculated for each natural gas component, relative ratios were calculated for methane:total organic compounds (TOC), VOC:TOC, HAP:TOC, VOC:Methane, HAP:Methane, BTEX:Methane, HAP:VOC, and BTEX:VOC. These relative ratios are presented in Table 9.

A similar analysis was performed for completions and recompletions from oil wells. The results of this analysis are presented in Table 10. The average VOC composition was 11.62 percent by volume, with a 95 percent confidence interval that ranges from 6.73 to 16.5 percent VOC by volume. As was done for gas wells, the average composition was normalized. The gas composition used for completions and recompletions for oil wells is presented in Table 8. The gas composition data was converted to weight percent using the same approach detailed for gas wells and are presented in Table 9.

Table 6. Weight Ratios to Use in Estimating Emissions

	Production	**Transmission**
Methane:TOC[a]	0.695	0.908
VOC[b]:TOC[a]	0.193	0.0251
HAP:TOC[a]	0.00728	0.000746
VOC[b]:Methane	0.278	0.0277
HAP:Methane	0.0105	0.000822
BTEX:Methane	0.00280	0.000322
HAP:VOC[b]	0.0377	0.0297
BTEX:VOC[b]	0.0101	0.0116

[a] TOC = all organic compounds listed in Table 3.

[b] VOC = all organic compounds listed in Table 3, except ethane and methane.

Table 7. Summary Statistics of Sensitivity Analysis on Gas Composition for Gas Well and Hydraulically Fractured Wells

Methane		*VOC*	
Mean	83.238	Mean	3.630
Standard Error	0.709	Standard Error	0.170
Median	86.581	Median	3.104
Mode	0	Mode	0.000
Standard Deviation	15.207	Standard Deviation	3.626
Sample Variance	231.244	Sample Variance	13.149
Kurtosis	12.943	Kurtosis	9.258
Skewness	-3.08	Skewness	2.262
Range	99.75	Range	29.560
Minimum	0	Minimum	0.000
Maximum	99.748	Maximum	29.560
Sum	38289.387	Sum	1655.427
Count	460	Count	456.000
Confidence Level(95.0%)	1.393	Confidence Level(95.0%)	0.334
	Volume Percent		Volume Percent
(Lower of 95% conf interval)	81.844	(Lower of 95% conf interval)	3.297
Methane	83.238	VOC	3.630
(Higher of 95% conf interval)	84.631	(Higher of 95% conf interval)	3.964

Table 8. Average Gas Composition for Completions and Recompletions of Gas and Oil Wells

	Average Volume Percent	
Pollutant	**Gas Wells**	**Oil Wells**
Carbon dioxide (CO_2)	1.631	1.00162
Nitrogen (N_2)	4.455	29.19
Methane (C1)	**83.081**	46.73
Ethane (C2)	4.924	10.17
Propane (C3)	2.144	6.62
i-Butane (i-C4)	0.348	1.067004
n-Butane (n-C4)	0.643	2.136346
i-Pentane (iC5)	0.095	0.550849
n-Pentane (nC5)	0.119	0.515798
Cyclopentane	0.005	0.001091
n-Hexane (n-C6)	0.155	0.005182
Hexanes (C6)	0.000	-
Cyclohexane	0.001	0.001455
Other Hexanes	0.010	0.007636
Methylcyclohexane	0.002	0.001818
C6+ Heavies	0.114	-
Heptanes (C7)	0.009	0.697080
n- Heptanes (C7)	0.000	0.001909
C8+ Heavies	0.004	0.005182
Benzene	0.005	0.006182
Toluene	0.003	0.000223
Ethylbenzene	0.000	0.000445
Xylenes	0.001	-
2,2,4-Trimethylpentane	0.000	0.000223
Helium	0.140	-
Oxygen	0.084	-
Hydrogen	0.001	0.575909
Hydrogen disulfide (H_2S)	2.027	0.709092
Total	**100**	**100**
VOC	**3.66**	**11.62**

Table 9. Weight Ratios to Use in Estimating Emissions for Completion and Recompletions

	Gas Wells	**Oil Wells**
Methane:TOC[a]	0.796	**0.4453**
VOC[b]:TOC[a]	0.116	**0.3729**
HAP:TOC[a]	0.0084	**0.0006**
VOC[b]:Methane	0.146	**0.8374**
HAP:Methane	0.0106	**0.0001**
BTEX:Methane	0.0006	**0.0007**
HAP:VOC[b]	0.0726	**0.0016**
BTEX:VOC[b]	0.0040	**0.0009**

[a] TOC = all organic compounds listed in Table 3.

[b] VOC = all organic compounds listed in Table 3, except ethane and methane.

Table 10. Summary Statistics of Sensitivity Analysis on Gas Composition for Oil Wells

Methane	
Mean	46.73157
Standard Error	4.196101
Median	49.63115
Mode	49.63115
Standard Deviation	19.68146
Sample Variance	387.3598
Kurtosis	1.385922
Skewness	-1.15094
Range	71.93094
Minimum	0.156
Maximum	72.08694
Sum	1028.095
Count	22
Confidence Level(95.0%)	8.72627
(Lower of 95% Conf interval)	38.0053
Methane	46.73157
(Higher of 95% Conf. Interval)	55.45784

VOC	
Mean	11.61755
Standard Error	2.193276
Median	9.697621
Mode	#N/A
Standard Deviation	7.274275
Sample Variance	52.91508
Kurtosis	1.438744
Skewness	1.127773
Range	25.91599
Minimum	1.381007
Maximum	27.297
Sum	127.793
Count	11
Confidence Level(95.0%)	4.886924
(Lower of 95% Conf interval)	6.730621
VOC	11.61755
(Higher of 95% Conf. Interval)	16.50447

REFERENCES

1. Letter and Attachments from Evans, J. M., Gas Research Institute, to G. Viconovic, EC/R Incorporated. Natural Gas BTEX Content. April 19, 1005. Legacy Docket Number A-94-04, Item II-D-35.

From: Eric Delzer
To: Reiten, John R.; Brady Pelton; Ron Ness
Cc: Norrell, Ryan; Beehler, Jace
Subject: Re: WEC Comments
Date: Thursday, March 28, 2024 12:09:48 PM
Attachments: Outlook-xjiwzean.png
NDPC Waste Emission Charge Official Comments.pdf
2024 03 26 Industry Trades WEC Comments_EPA-HQ-OAR-2023-0434_FINAL_FULL.pdf
AXPC WEC Comment Letter_Final.pdf
2024 IPAA Comments on Inflation Reduction Act - WEC Proposal - March 26.pdf w Appendices.pdf

---

Thanks for sharing John. Here are the comments from the industry.

Eric Delzer
Regulatory Affairs Manager
North Dakota Petroleum Council
701-204-7348
edelzer@ndoil.org
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501

From: Reiten, John R. <jreiten@nd.gov>
Sent: Thursday, March 28, 2024 11:01 AM
To: Brady Pelton <bpelton@ndoil.org>; Eric Delzer <edelzer@ndoil.org>; Ron Ness <ronness@ndoil.org>
Cc: Norrell, Ryan <ryan.norrell@nd.gov>; Beehler, Jace <jabeehler@nd.gov>
Subject: WEC Comments

Attached are ND's comments.

Have a great Easter weekend!

John Reiten
Senior Policy Advisor
Office of Governor Doug Burgum
Email: jreiten@nd.gov
Cell: (701) 328-2281

From: Micaela Rud
To: Reiten, John R.
Subject: Williston Basin Core Workshop Confirmation 2024
Date: Thursday, April 18, 2024 12:03:30 PM

You don't often get email from mrud@ndoil.org. Learn why this is important

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Good morning John,

I hope you are getting excited to attend WBPC 2024 like we are!

We are working on finalizing numbers for the Core Workshop and the WBPC Conference, and wanted to confirm your attendance. If you could please reach out to Becky Ness at [redacted] [redacted] to let us know if you will be attending or not, that would be great!

If you have any other questions, please let us know.

Thank you!

Micaela Rud
Executive Assistant
North Dakota Petroleum Council
General: 701-223-6380
Direct: 701-204-7345
mrud@ndoil.org

From: Reva Kautz
To: Reva Kautz
Subject: Williston Basin Petroleum Conference May 14-16, 2024 in Bismarck, North Dakota
Date: Monday, March 25, 2024 5:04:51 PM
Attachments: image.png
image.png
Outlook-rc3m2ei3.jpg
Outlook-ig2elt0a.jpg
2024 WBPC Agenda to Share.docx

Thank you for registering for the upcoming Williston Basin Petroleum Conference May 14-16, 2024!

Please help promote the conference by forwarding this email to your contacts who could benefit from attending this amazing conference, as well.

See all Williston Basin Petroleum Conference details at https://www.wbpcnd.com/

In appreciation,

Reva Kautz
Communications Director
North Dakota Petroleum Council
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501
Office: 701.557.7744
rkautz@ndoil.org
www.ndoil.org

From: Reva Kautz
To: Reva Kautz
Subject: Williston Basin Petroleum Conference May 14-16, 2024 in Bismarck, North Dakota
Date: Monday, March 25, 2024 5:04:51 PM
Attachments: image.png
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Outlook-rc3m2ei3.jpg
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2024 WBPC Agenda to Share.docx

Thank you for registering for the upcoming Williston Basin Petroleum Conference May 14-16, 2024!

Please help promote the conference by forwarding this email to your contacts who could benefit from attending this amazing conference, as well.

See all Williston Basin Petroleum Conference details at https://www.wbpcnd.com/

In appreciation,

Reva Kautz
Communications Director
North Dakota Petroleum Council
100 West Broadway, Suite 200
PO Box 1395
Bismarck, ND 58501
Office: 701.557.7744
rkautz@ndoil.org
www.ndoil.org

From: Brady Pelton
To: Brady Pelton
Cc: Micaela Rud
Subject: YOU"RE INVITED! - ND Petroleum Council March Board Events
Date: Monday, February 12, 2024 5:16:26 PM
Attachments: image001.png
image002.png
UND EERC Luncheon and Tour Flyer.pdf
Importance: High

Good afternoon, North Dakota leaders:

The North Dakota Petroleum Council Board of Directors and guests are eagerly awaiting our February 29-March 1 visit to Grand Forks and the University of North Dakota!

In advance of our two-day visit, we wanted to share the invitation below from the Energy & Environmental Research Center (EERC):

> You are cordially invited to a luncheon at the University of North Dakota (UND) Energy & Environmental Research Center (EERC) on Friday, March 1, 2024, at noon. Attendees include state and local leaders and North Dakota Petroleum Council members.
>
> Following the luncheon, you have an opportunity to tour the EERC or the College of Engineering & Mines (CEM). You can join the EERC for a journey through the EERC's expanding array of projects, deeply meaningful for our state, and the entire region.
>
> - Option 1: At the EERC, the tour will include, but not be limited to, research on Bakken, salt caverns, rare-earth elements, CO_2 capture and storage, development of new materials, and the latest update to our expanding hydrogen program. During the tour, you will hear from our professional research staff who bring a wealth of expertise to these impactful areas. The EERC team is looking forward to answering any questions you may have and the opportunity to connect with leadership from North Dakota and our entire region.
> - Option 2: Dean Brian Tande will lead a tour of the College of Engineering & Mines National Security Corridor and the Collaborative Energy Center. CEM research has grown by more than 40% in the past several years, with over $9M in areas such as energy, rare-earth elements, UAS, and national security.
>
> Please RSVP by February 15, 2024, for both the luncheon and the tour at this link: use this link.

Capping off the events on Friday, NDPC will host a social at the CanadInn’s Playmakers Lounge from 4:30 to 6:00 p.m. and then host guests at the Ralph as UND takes on Western Michigan in some good old North Dakota hockey. Hockey tickets are sponsored by our great friends at AE2S, Construction Engineers, and the UND Alumni Association & Foundation. We have a hockey ticket for you. However, if you have access to other tickets, please use those and find us on the suite level (Suites 201 and 204; Alumni Association suite is 225).

In order to best prepare for meals and other logistics, we ask that you RSVP by February 15th at each of the links below.

Friday, March 1 - EERC Lunch & Tour Invite
Friday, March 1 - NDPC Social & Hockey Night

Thank you all for your continued support and please contact me with any questions. We look forward to seeing each of you.

Best regards,
Brady

BRADY PELTON
Vice President & General Counsel

North Dakota Petroleum Council
100 West Broadway, Suite 200
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Bismarck, ND 58501

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bpelton@ndoil.org

www.NDOil.org | www.NDOilFoundation.org

UND EERC INVITES YOU TO A

LUNCHEON & TOUR @ UND

Join us at the EERC for a lunch with, state and local leaders, and the North Dakota Petroleum Council.

MARCH 1, 2024

from noon to 3:00 p.m.

Energy & Environmental Research Center
15 North 23rd Street
Grand Forks, ND 58202

CLICK HERE TO RSVP

From: Tessa Sandstrom
To: ND Petroleum Foundation
Subject: Join us for the Bakken Rocks CookFest on July 18 in Tioga!
Date: Wednesday, June 12, 2024 3:21:56 PM
Attachments: 2024 CookFest Poster.pdf

Good afternoon!

The North Dakota Petroleum Foundation will be hosting this year's Bakken Rocks CookFest in Tioga on Thursday, July 18 in Tioga. The event includes a Bakken Basics Information Session from 2:30-4 p.m. in the Tioga Community Center and a BBQ, Education Tent, live music, games and activities for kids, and more from 4-7 p.m. in the Tioga Park.

This free, family-friendly event has been an important outreach event for the Foundation and the oil and gas industry. This year, we're expecting anywhere between 2,500 and 3,500 people to attend this year's event, and hope you will join us to meet with constituents and enjoy a great evening!

We appreciate your support in the past and we hope to see you at this year's event!

Sincerely,

TESSA SANDSTROM
Executive Director
NORTH DAKOTA PETROLEUM FOUNDATION

O: 701.557.3972

www.NDPetroleumFoundation.org | www.NDOil.org

From: [Lemieux, Kayla M.]
To: [Reva Kautz]
Cc: [Gulleson, Connie M.]
Subject: May 15th Dinner - Agenda
Date: Tuesday, May 14, 2024 11:59:13 AM
Attachments: Agenda WPBC VIP Dinner at Gov Residence 5 15 2024.pdf
image001.png
image002.png
image003.png
image004.png
image005.png

Hello Reva,
We are trying to save on paper materials on the tables so we will be adding the agenda to the back of the menu cards. Is the attached agenda the final agenda? Wondering if the order of speakers is confirmed as well? We will have these printed and placed on the tables

With Gratitude,

Kayla Lemieux
Executive Assistant to the Governor

701.328.4084 • klemieux@nd.gov • governor.nd.gov

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From:	Christopher Rager
To:	Gulleson, Connie M.
Cc:	Reiten, John R.
Subject:	RE: 26th State Government Relations Summit
Date:	Wednesday, July 24, 2024 2:04:06 PM
Attachments:	image001.png image002.png image003.png image004.png

---

Connie,

Thank you for the follow up. We greatly appreciate Governor Burgum's consideration of this request. While the timing didn't work, we look forward to continuing to work together.

Best,

Chris

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Wednesday, July 24, 2024 2:09 PM
To: Christopher Rager <RagerC@api.org>
Cc: Reiten, John R. <jreiten@nd.gov>
Subject: 26th State Government Relations Summit

Good afternoon, Mr. Rager!

I hope this letter finds you in good health and spirits! I am writing to express our sincerest regrets as Governor Burgum will be unable to attend the 26th State Government Relations Summit on September 25th in Washington, DC. It is with great disappointment that we decline your gracious invitation due to scheduling conflicts.

Governor Burgum extends his gratitude for the invitation to be your special guest and speak at the event. It is always an honor to be invited to events that bring our communities together and promote positive initiatives.

Please convey our apologies to the organizers. We trust that the event will be a huge success and please keep our office informed about any future opportunities that we can participate in.

Wishing you a successful and memorable summit!

With gratitude,

Connie

Connie Gulleson
Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

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From: Lemieux, Kayla M.
To: Reiten, John R.; Gulleson, Connie M.
Subject: RE: API Follow Up
Date: Friday, July 19, 2024 1:55:59 PM
Attachments: API Draft Agenda.docx
image001.png

Thank you John!

Connie, I made one that was a little easier to copy/paste and put in the calendar invite – also printed a copy for your files as well.

Thank you!

Kayla Lemieux
Executive Assistant to the Governor

From: Reiten, John R. <jreiten@nd.gov>
Sent: Friday, July 19, 2024 1:39 PM
To: Gulleson, Connie M. <cmgulleson@nd.gov>; Lemieux, Kayla M. <klemieux@nd.gov>
Subject: Fwd: API Follow Up

From: Christopher Rager <RagerC@api.org>
Sent: Friday, July 19, 2024 1:37 PM
To: Reiten, John R. <jreiten@nd.gov>
Subject: RE: API Follow Up

John,

Thanks for the follow up. Below is an agenda overview.

We're currently confirming panelists for each panel. Panelists will be a mix of public and private sector individuals from different industries and sectors.

The initial RSVP went out this week. Moving forward, we're happy to share both the RSVP and confirmed panelist lists.

Let me know if you have any questions.

Have a great weekend!!

Chris

*****DRAFT*****

2024 STATE GOVERNMENT AFFAIRS SUMMIT

PANEL OVERVIEW

API HQ – 200 Massachusetts Ave NW, Washington, DC 20001

Wednesday, September 25th

12:00PM – 1:00PM	LUNCH & KEYNOTE SPEAKER: ***Governor Doug Burgum [TENTATIVE]***
1:15PM – 2:30PM	PLENARY I: OUR ENERGY FUTURE: POLICYMAKING, MARKETS AND TRENDS
2:45PM – 4:00PM	PLENARY II: FUELING AMERICA: THE FUTURE OF U.S. TRANSPORTATION
4:15PM – 5:30PM	PLENARY III: LOWER CARBON TECHNOLOGIES: BULLISH OR BEARISH?
6:00PM – 8:00PM	RECEPTION & DINNER (L'ARDENTE)

[ADJOURNMENT]

Thursday, September 26th

8:00AM – 8:45AM	WELCOME & BREAKFAST
9:00AM – 10:30AM	PLENARY IV: 2024 ELECTIONS: POLLING, POLITICS & INDUSTRY OUTLOOK
10:45AM – 12:00PM	THE RISE OF AI: ENERGY, POLICY & POLITICS

[ADJOURNMENT]

From: Amanda Remynse
To: Gulleson, Connie M.; Amy Jo Johnson
Cc: Impact Dakota
Subject: RE: Face of Manufacturing
Date: Wednesday, December 27, 2023 8:50:58 AM
Attachments: image001.png
image002.png
image003.png
image004.png

I’m totally good planning to start at the capitol at 11:00 with Lt. Gov, proclamation, photo opp and be done at 11:30-11:40? We would invite her/team to lunch if you’d like, it will be at Ramkota/Bismarck Hotel but the logistics are clunky, I’ll leave that up to your team. Thanks for getting that on the schedule – appreciate it!

ALR

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Tuesday, December 26, 2023 4:42 PM
To: Amanda Remynse <amanda@ndchamber.com>; Amy Jo Johnson <amyjo@ndchamber.com>
Subject: RE: Face of Manufacturing

Hello!

I do have a hold on the calendar but if we could wrap up by 1 pm, that would be great as the Lt. Governor does have another meeting scheduled that starts at 1 pm. I have blocked 11 am to 1 pm so hopefully we can accommodate whatever develops for the day.

Let me know as things progress.

With gratitude,
Connie

Connie Gulleson
Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

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From: Amanda Remynse <amanda@ndchamber.com>
Sent: Tuesday, December 26, 2023 11:55 AM
To: Gulleson, Connie M. <cmgulleson@nd.gov>; Amy Jo Johnson <amyjo@ndchamber.com>
Subject: Face of Manufacturing

Connie –

Wanted to get on calendar as soon as possible for a repeat of what we did this past year! On Oct 6 we had Lt. Gov Miller talk to our manufacturers at the capitol with the MFG Day proclamation. One piece of feedback we heard was it was hard to get MFG'ers away from their operations on the day and we are hoping we can do something similar this coming year – a luncheon with a capitol/Memorial Hall address with proclamation on Sept 23.

Can we put a hold for signing or something for that day? Either 11 or 1? Half hour? With Lt. Gov or Gov – we appreciate any time and I know the campaign spotlights really enjoyed the importance of the proclamation with the conversation this past Oct.

I'm starting the conversation but also passing over to Amy Jo, our events coordinator who will be responsive to you, especially compared to the likes of me! We have a soft hold at a venue and have approved with Impact Dakota as well.

Let's start here.

<<ask about GrowND: Workforce Solutions Showcase>>

Amanda Remynse
VP [Operations & Outreach] | Greater North Dakota Chamber
PO Box 2639, Bismarck ND 58502
ndchamber.com | amanda@ndchamber.com | 701.222.0929

From: Gulleson, Connie M.
To: Miller, Tammy J.
Subject: RE: GNDC Policy Summit
Date: Thursday, June 27, 2024 3:30:00 PM
Attachments: image004.png
image005.png
image006.png
image007.png
image008.png
image009.png
image001.png

Good morning!

You are registered. I entered you to be both in-person and online, so you have the option to do what works best at the time. Agenda is updated in the calendar invite.

From: Miller, Tammy J. <tjmiller@nd.gov>
Sent: Wednesday, June 26, 2024 5:12 PM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: FW: GNDC Policy Summit

Please register me and add to my calendar. Thanks Connie.

Tammy J. Miller
Lieutenant Governor

701.328.2200 • tjmiller@nd.gov • governor.nd.gov

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-
Sign up to receive updates from Governor Burgum
-
-
-

From: Andrea Pfennig <andrea@ndchamber.com>
Sent: Tuesday, June 25, 2024 3:37 PM
Subject: GNDC Policy Summit

Hello,

GNDC would like to invite you to attend our 2024 Policy Summit.

This annual event brings together business and government leaders to discuss policies impacting North Dakota's business climate and address issues impacting our state's future growth. This premier public policy forum is a non-partisan event open to members and non-members of GNDC.

Details
When: Tuesday, Sept. 10
Where: Bismarck Event Center, 315 S 5th St Bismarck ND 58504

Use code **MEADOWLARK** when registering. If you have any questions, let me know.

We look forward to seeing you there!
Andrea.

Andrea Pfennig
Director of Government Affairs | Greater North Dakota Chamber
PO Box 2639, Bismarck ND 58502
ndchamber.com | andrea@ndchamber.com | 701.222.0929

From: Amanda Remynse
To: Beehler, Jace
Cc: Gulleson, Connie M.
Subject: Re: GNDC Public Policy
Date: Monday, January 8, 2024 9:49:53 PM
Attachments: image001.png

Jace, sorry for the delay - policy summit is September 10th in Bismarck. Our PAC social will be that day as well at 4:31. When I'm back I'm office, I will send over our slate of events as we have another event in June that we are teaming up with Minnkota in GF.

Get Outlook for Android

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Monday, January 8, 2024 12:23:50 AM
To: Amanda Remynse <amanda@ndchamber.com>
Cc: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: GNDC Public Policy

Hello Amanda,

Can you share with me when you plan on holding your 2024 public policy conference? We are working on the schedule for our conferences this year and want to ensure we don’t duplicate.

Thanks,
Jace

Jace Beehler
Chief of Staff
Office of the Governor
701.328.2201 • 701.610.9431(m) • jabeehler@nd.gov • www.nd.gov

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From: Kristin A. Westmoreland
To: Gulleson, Connie M.
Cc: Rolf Hanson
Subject: RE: Info for Upcoming Annual State of American Energy Program
Date: Wednesday, December 27, 2023 3:09:40 PM
Attachments: image001.png
image002.png
image003.png
image004.png

Hi Connie –
Hope you are having a wonderful holiday. I wanted to give you a quick update that Gov. Stitt from OK just confirmed his participation in our State of American Energy. No doubt yall are juggling a lot of different requests so let us know if you need anything in the meantime.
Thanks!
Kristin

From: Kristin A. Westmoreland
Sent: Tuesday, December 19, 2023 10:10 AM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Cc: Rolf Hanson <Hansonr@api.org>
Subject: RE: Info for Upcoming Annual State of American Energy Program

Connie –

Thanks for reaching out and sorry I missed your call. The agenda is pretty straightforward – see below. We are expecting near 400 policy makers and thought leaders for the oil and gas industry as well as Capitol Hill and the administration. We would welcome the Governor's participation (as a fireside chat or a standalone address, depending on his preference).

Looking forward to hearing from you and don't hesitate to reach out with any additional questions.

Thanks again,
Kristin

2024 State of American Energy
January 10, 2024
7:30 – 9:30 a.m.
Capitol Turnaround
700 M Street SE, Washington, DC 20003

Doors open at 7:30 a.m.

Breakfast available from 7:30 – 8:30 a.m.

1. **Opening: Lights on Energy**
   Megan Bloomgren, Senior Vice President, Communications, API

2. **The Bipartisan Path on Energy in a Divided Congress**
   Senator John Hickenlooper, U.S. Senate (CO)
   Senator Bill Cassidy, U.S. Senate (LA)
   Moderated by Amanda Eversole, Executive Vice President and Chief Advocacy Officer, API

3. **The State of American Energy**
   Mike Sommers, President and CEO, API

4. **Closing Remarks**
   Megan Bloomgren, Senior Vice President, Communications, API

Kristin Westmoreland
Vice President and Chief of Staff
703.300.0385
e: westmorelandk@api.org
www.api.org
-

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Tuesday, December 19, 2023 9:46 AM
To: Rolf Hanson <Hansonr@api.org>; Kristin A. Westmoreland <WestmorelandK@api.org>
Subject: Info for Upcoming Annual State of American Energy Program

Good morning! Happy Tuesday!!

I am currently working on Governor Burgum's schedule and would like to request more information in regard to the Annual State of American Energy program for January 10th, 2024. Is there an agenda for the day? Is it multiple days? If there are any details and an agenda that you can send us to assist in our planning, that would be more appreciated.

I look forward to working with you on this request.
With gratitude,

Connie

Connie Gulleson
Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

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From: Gulleson, Connie M.
To: Amanda Remynse
Subject: RE: Intro and confirmation - MFG Sept 27
Date: Monday, June 24, 2024 2:22:00 PM
Attachments: image001.png
image002.png
image003.png
image004.png

Amanda –

Hello!! Unfortunately, I cannot confirm either one of them at this point. Schedules are just too fluid. If I had to make an assumption, I would be that it will probably by Lt. Governor Miller but I will keep you updated as the date gets closer.

I just resent the calendar invite and included Mallory. Please let me know if they do not come through again.

With gratitude,
Connie

Connie Gulleson
Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

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From: Amanda Remynse <amanda@ndchamber.com>
Sent: Monday, June 17, 2024 1:33 PM
To: Gulleson, Connie M. <cmgulleson@nd.gov>; Mallory Jensen <mallory@ndchamber.com>
Subject: FW: Intro and confirmation - MFG Sept 27

Connie – can you confirm calendar? I don't see this and I want to make sure Mallory gets it as she will be carrying logistics of this event. I think 11 – 11:20 was perfect, do you happen to know who it may be at this point? Mostly to plan prepare?

Amanda Remynse
VP [Operations & Outreach] | Greater North Dakota Chamber
PO Box 2639, Bismarck ND 58502
ndchamber.com | amanda@ndchamber.com | 701.222.0929

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Wednesday, April 10, 2024 2:27 PM
To: Amanda Remynse <amanda@ndchamber.com>; Mallory Jensen <mallory@ndchamber.com>
Subject: RE: Intro and confirmation

Amanda,

I sent you a calendar invite for the27th at 11 am. I am only able to do about 20 min though, but we will have an opportunity to visit and take a photo.

Please provide the list of attendees when the date gets closer as well as where they work and any bio information that may be available.

Any questions, I am happy to assist.

Looking forward to working with you on this request.

With gratitude,

Connie

Connie Gulleson

Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

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From: Amanda Remynse <amanda@ndchamber.com>
Sent: Wednesday, April 10, 2024 1:21 PM
To: Gulleson, Connie M. <cmgulleson@nd.gov>; Mallory Jensen <mallory@ndchamber.com>
Subject: RE: Intro and confirmation

Let's plan for a before lunch. Luncheon could be at 12:00 – if your team is good with it, we could do a meet at capitol for proclamation reading and meet and greet and pic at 11:00 – that would give us about 45 minutes and then we'd leave and head to luncheon and if you are okay with it, we wouldn't anticipate Gov or Lt to attend given their current schedule. Not that uninvited but that doesn't commit – let me know your thoughts there.

June 4 – sounds good.

Sept 10 – thank you.

aLR

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Tuesday, April 9, 2024 3:18 PM
To: Amanda Remynse <amanda@ndchamber.com>
Subject: RE: Intro and confirmation

Hello!

We should probably look at doing something maybe before lunch as we have another speaking engagement in the Capitol already scheduled for Friday, September 27th at 1 pm. What time would the luncheon start so that we can work it back as to when would be a good time to meet at the Capitol? I will put a hold on the calendar for the 27th but if you could let me know an approx. timeframe, I would greatly appreciate it. I am not sure if anyone would be attending the luncheon but we can sure work on that to see if we can get someone there.

June 4th – Unfortunately, the Governor will be unavailable to attend but I can check with Lt. Governor Miller to see on her availability.

Sept 10th – Policy Summit is already on our calendars.

Let me know what else I can assist with.

With gratitude,

Connie

Connie Gulleson

Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

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From: Amanda Remynse <amanda@ndchamber.com>
Sent: Tuesday, April 9, 2024 10:13 AM
To: Gulleson, Connie M. <cmgulleson@nd.gov>; Mallory Jensen <mallory@ndchamber.com>
Subject: Intro and confirmation

Connie!

We've had a few things floating around but wanted to connect you with our Program and Event Coordinator, Mallory will also be there to work through logistics or answer any questions you may have.

Confirmation:

-Sept 27 – MFG Day proclamation. We are doing a luncheon at Bismarck Hotel and then hoping for something similar to what we did this past October. A bit of a meet and greet in memorial hall with a reading of the proclamation and a photo op. Last fall, Lt Gov Miller did not come to our breakfast as it was a bit clunky with the back and forth – we are open to anything whether it be a before lunch or after with an invite to gov staff to attend. Wanted to check if we had confirmation for this day as Commerce's team is trying to make plans.

Also – Events that Jace has asked about:

-June 4: ND Future Forum – Grand Forks, Minnkota

-Sept 10: Policy Summit – Bismarck Event Center with PAC social to follow

Thanks – looking forward to shoring up any details on Sept 27 event.

<<ask about GrowND: Workforce Solutions Showcase>>

Amanda Remynse

VP [Operations & Outreach] | Greater North Dakota Chamber

PO Box 2639, Bismarck ND 58502

ndchamber.com | amanda@ndchamber.com | 701.222.0929

GNDC
Greater North Dakota Chamber

From: Amanda Remynse
To: Gulleson, Connie M.; Mallory Jensen
Subject: RE: Intro and confirmation
Date: Wednesday, April 10, 2024 1:21:35 PM
Attachments: image002.png
image003.png
image004.png
image005.png

Let's plan for a before lunch. Luncheon could be at 12:00 – if your team is good with it, we could do a meet at capitol for proclamation reading and meet and greet and pic at 11:00 – that would give us about 45 minutes and then we'd leave and head to luncheon and if you are okay with it, we wouldn't anticipate Gov or Lt to attend given their current schedule. Not that uninvited but that doesn't commit – let me know your thoughts there.

June 4 – sounds good.
Sept 10 – thank you.

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Sent: Tuesday, April 9, 2024 3:18 PM
To: Amanda Remynse <amanda@ndchamber.com>
Subject: RE: Intro and confirmation

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Sept 10th – Policy Summit is already on our calendars.

Let me know what else I can assist with.
With gratitude,
Connie

Connie Gulleson
Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

From: Amanda Remynse <amanda@ndchamber.com>
Sent: Tuesday, April 9, 2024 10:13 AM
To: Gulleson, Connie M. <cmgulleson@nd.gov>; Mallory Jensen <mallory@ndchamber.com>
Subject: Intro and confirmation

Connie!

We've had a few things floating around but wanted to connect you with our Program and Event Coordinator, Mallory will also be there to work through logistics or answer any questions you may have.

Confirmation:
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Also – Events that Jace has asked about:
-June 4: ND Future Forum – Grand Forks, Minnkota
-Sept 10: Policy Summit – Bismarck Event Center with PAC social to follow

Thanks – looking forward to shoring up any details on Sept 27 event.

<<ask about GrowND: Workforce Solutions Showcase>>

Amanda Remynse
VP [Operations & Outreach] | Greater North Dakota Chamber
PO Box 2639, Bismarck ND 58502
ndchamber.com | amanda@ndchamber.com | 701.222.0929

From: Beehler, Jace .
To: Gulleson, Connie M.
Subject: RE: Intro to AXPC
Date: Friday, June 30, 2023 12:44:16 PM
Attachments: image001.png
image002.png

Hi Anne,

Thank you again for the invite. We are trying to get you an answer ASAP. Can you share what other elected officials are invited/attending?

Thank you,
Jace

From: Bradbury, Anne <anne.bradbury@axpc.org>
Sent: Tuesday, June 20, 2023 11:13 AM
To: Beehler, Jace . <jabeehler@nd.gov>; Zac Weis <zaweis@marathonoil.com>
Subject: RE: Intro to AXPC

Hi Jace!
Realizing that your schedule has gotten significantly more hectic lately…I wanted to check back on this to see if it was still on the radar. I think it would be a great group for the Governor to meet with and we'd love to include him in dinner if he's able to attend. A full list of our board members can be found here.
Thank you,
Anne

From: Beehler, Jace . <jabeehler@nd.gov>
Sent: Wednesday, May 24, 2023 11:29 AM
To: Bradbury, Anne <anne.bradbury@axpc.org>; Zac Weis <zaweis@marathonoil.com>
Subject: RE: Intro to AXPC

Thank you for the invitation, Anne.

I will get this to our scheduler, and we will get back to you as soon as possible.

All the best,
Jace

From: Bradbury, Anne <anne.bradbury@axpc.org>
Sent: Wednesday, May 24, 2023 10:23 AM

To: Beehler, Jace . <jabeehler@nd.gov>; Zac Weis <zaweis@marathonoil.com>
Subject: RE: Intro to AXPC

Hi Jace! I hope you are well.
Following up on Zac's very kind introduction, I wanted to invite you to have dinner with my board of directors when they are in OKC on July 20th.   Our board consists of the CEO's of the leading ND and national oil and gas producers—including our Chair, Lee Tillman of MRO.
We'd be delighted to have the Governor join us for discussion and fellowship. We expect Gov Stitt to join us as well.
Thanks for you consideration and please let me know if you have any questions.
Best,
Anne

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Monday, September 26, 2022 11:12 AM
To: Bradbury, Anne <anne.bradbury@axpc.org>; Zac Weis <zaweis@marathonoil.com>
Subject: RE: Intro to AXPC

Thank you, Zac and Anne.

We appreciate the reach out and the willingness stay connected with our team. Please let me know if the is an opportunity that would make sense for us to connect or a strategic time to touch base with your board.

Looking forward to working together!
Jace

Jace Beehler
Chief of Staff
Office of the Governor
701.328.2201 • 701.610.9431(m) • jabeehler@nd.gov • www.nd.gov

---

From: Bradbury, Anne <anne.bradbury@axpc.org>
Sent: Monday, September 26, 2022 8:44 AM
To: Zac Weis <zaweis@marathonoil.com>; Beehler, Jace <jabeehler@nd.gov>
Subject: RE: Intro to AXPC

Thanks Zac!
Hi Jace, it was so great the meet the Governor at the NDPC meeting last week. As Zac mentioned, we represent most of the largest Bakken producers and work closely with the ND DC delegation on federal issues that impact industry. Would love to explore opportunities to work together more closely, and to increase connectivity with the Governor and my Board.
All the best,
Anne

From: Weis, Zachary A. (MRO) <zaweis@marathonoil.com>
Sent: Thursday, September 22, 2022 11:57 PM
To: jabeehler@nd.gov; Bradbury, Anne <anne.bradbury@axpc.org>
Subject: Intro to AXPC

Jace,
Making the connection with you to Anne Bradbury, CEO of American Exploration & Production Council. Anne followed the Governor yesterday after he spoke at the NDPC Annual Meeting. Anne and her team are an integral part of our industry, representing the US Oil & Gas and the interests of energy producing states in DC. I did a quick look at the AXPC membership and it looks like we have 10 large Bakken producing operators serving on the AXPC board, including Marathon Oil's CEO Lee Tillman who is currently the chairman of the board.

I know many of the AXPC board members know Governor Burgum individually. I want to make sure that you and the Governor know that if there is every any opportunity for us to assist or to open a dialogue with the Governor that we are always her to help.

Zac Weis
Government & Community Relations Manager
Marathon Oil Company
Mobile: 701-400-2989

MarathonOil

From: Gulleson, Connie M.
To: Bradbury, Anne
Cc: Beehler, Jace .; Carolyn Quinn
Subject: RE: July 20th Meeting - Governor Burgum
Date: Thursday, July 6, 2023 3:40:00 PM
Attachments: image001.png
image002.png
image003.png
image004.png

Anne (and Carolyn),

Thank you so much for getting back to me so quickly! I greatly appreciate it! I will inform our team and get back to you as soon as we have details figured out. One request, do you have bios/background information for those individuals that will be at the meeting? If you do, could you forward that information on to me? Thank you so much in advance!!

Will be in touch.
With gratitude,
Connie

Connie Gulleson
Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

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From: Bradbury, Anne <anne.bradbury@axpc.org>
Sent: Thursday, July 6, 2023 3:09 PM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Cc: Beehler, Jace . <jabeehler@nd.gov>; Carolyn Quinn <cquinn@axpc.org>
Subject: RE: July 20th Meeting - Governor Burgum

Good afternoon Connie,
Adding carolyn from my team to correct me on anything I get wrong here!

1. The dinner will be held at the 49th floor of Devon Tower in OKC at Vast.
2. List is below
3. Yes, the dinner will begin at 630. There is a larger reception prior that starts at 5pm that he is welcome to attend as well.
4. We will likely wrap around 830-9.
5. No specific agenda—Gov Stitt will be in attendance as well and we would ask each to speak to the group about energy issues and the importance of domestic energy production from their perspective.
6. We would ask him to make brief remarks and take Q and A. It is a relatively intimate setting and all discussion is off the record or Chatham house rules.
7. Please let us know what other information we can provide!

Best,

Anne

#	Name	Title	Company Name
1	John Christmann	CEO & President	Apache Corporation
2	Jeff Fisher	CEO	Ascent Resources
3	Anne Bradbury	President & CEO	AXPC
4	Eric Greager	President & CEO	Baytex Energy Ltd.
5	Joe Gatto	President and CEO	Callon Petroleum
6	Nick Dell'Osso	CEO	Chesapeake Energy
7	Danny Brown	President and CEO	Chord Energy
8	Nick Olds	EVP, Lower 48	ConocoPhillips
9	Craig Bryksa	President & CEO	Crescent Point Energy
10	Rick Muncrief	President/CEO	Devon Energy
11	Travis Stice	Chairman and CEO	Diamondback Energy
12	Robert Hutson	CEO	Diversified Energy
13	Hardy Murchison	President & CEO	Encino Energy
14	Ian Dundas	President & CEO	Enerplus
15	Toby Rice	CEO	EQT Corporation
16	Greg Hill	President & COO	Hess Corporation
17	Greg Lalicker	CEO	Hilcorp
18	Tom Hart	President and Chief Executive Officer	Jonah Energy
19	Lee Tillman	Chairman, President & CEO	Marathon Oil Company
20	Ken Waits	President and CEO	Mewbourne Oil Company
21	Brendan McCracken	President & CEO	Ovintiv Inc.
22	James Walter	Co-CEO	Permian Resources
23	Richard Dealy	President & COO	Pioneer Natural Resources USA, Inc.
24	Christopher Valdez	CEO	PureWest
25	Dennis Degner	President and CEO	Range Resources
26	Justin Loweth	President	Seneca Resources
27	Herb Vogel	CEO	SM Energy
28	Jason Pigott	President & CEO	Vital Energy
29	Governor J. Kevin Stitt	Governor of Oklahoma	

8.

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Thursday, July 6, 2023 3:22 PM
To: Bradbury, Anne <anne.bradbury@axpc.org>
Cc: Beehler, Jace . <jabeehler@nd.gov>
Subject: July 20th Meeting - Governor Burgum

Good afternoon, Anne!

My name is Connie Gulleson, and I am the Director of Scheduling for Governor Doug Burgum. I am reaching out to see if it would be possible to get some more details regarding the upcoming meeting of AXPC's Board of Directors in Oklahoma City on Thursday, July 20th. I am working to see if we can make this meeting happen with the Governor's schedule. Couple of questions:

Where is the meeting going to be held?

Who all would be attending?

Will the meeting start at 6:30 pm CT?

How long is the meeting expected to last?

Is there an agenda or topics of interest to be discussed?

Expected role of the Governor?

Any information would be greatly appreciated!! Thank you for your assistance. Please respond to this email or my direct line is 701.328.4222. I look forward to hearing from you.

With gratitude,
Connie

Connie Gulleson
Director of Scheduling

701.328.4222 • cmgulleson@nd.gov • governor.nd.gov

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From: Gulleson, Connie M.
To: Beehler, Jace
Subject: RE: Registration Now Open for NDPC Annual Meeting in September
Date: Tuesday, July 30, 2024 3:05:00 PM

Done

From: Beehler, Jace <jabeehler@nd.gov>
Sent: Tuesday, July 30, 2024 2:51 PM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: Fw: Registration Now Open for NDPC Annual Meeting in September

Hi Connie,

Please ensure this is on the Gov calendar as a hold.

Thank you

From: North Dakota Petroleum Council <ndpc@ndoil.org>
Sent: Tuesday, July 30, 2024 1:46 PM
To: Beehler, Jace <jabeehler@nd.gov>
Subject: Registration Now Open for NDPC Annual Meeting in September

The NDPC Annual Meeting is Back in Watford City!

Join us September 17-19, 2024 in the heart of the Bakken!

The 43rd North Dakota Petroleum Council Annual Meeting is scheduled for September 17-19, 2024, at the Rough Rider Center in Watford City, ND.

Attendees can look forward to hearing from the Bakken’s foremost industry leaders, networking with more than 400 industry professionals, and learning about the latest trends in oil and gas. From the socials to the Annual Industry Awards Luncheon to the knowledgeable speakers and panels presenting on what's new in the Bakken, there is something for everyone at the Annual Meeting!

Registration is now open!

Register

NDPC Logo

From: Ron Ness
To: Reva Kautz; Gulleson, Connie M.
Subject: RE: VIP Dinner at the Governor"s Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference
Date: Tuesday, April 23, 2024 9:48:55 AM

The menu looks outstanding! Thank you.

From: Reva Kautz <rkautz@ndoil.org>
Sent: Tuesday, April 23, 2024 9:42 AM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Cc: Ron Ness <ronness@ndoil.org>; Reva Kautz <rkautz@ndoil.org>
Subject: Re: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

Our count is currently at 33 but we would like to invite 2 more VIPs if possible. Since the seating arrangement is going to round tables, is there an option to have 35 in attendance?

from your previous email
Menu:

App – Walleye Cakes with Creole aioli and corn succotash

Main Dish – working on this with Chef– it will be a beef entrée – will keep you posted
Dessert – Peach cobber with vanilla bean ice cream and bourbon caramel.

Has the main dish been decided?

When the drinks have been ordered and paid for, our team will let you know which store and the items in the order.

Are there any other details to still work on, Connie?

In appreciation,

Reva Kautz

Communications Director

North Dakota Petroleum Council

100 West Broadway, Suite 200

PO Box 1395

Bismarck, ND 58501

Office: 701.557.7744

rkautz@ndoil.org

www.ndoil.org

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MAY 14-16,2024 | BISMARCK, ND
BAKKEN NOW
WILLISTON BASIN PETROLEUM CONFERENCE
SAVE THE DATE
WWW.WBPCND.COM

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Tuesday, April 16, 2024 3:26 PM
To: Reva Kautz <rkautz@ndoil.org>
Subject: RE: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

Thank you for the update. We will accommodate accordingly.

With gratitude,

Connie

From: Reva Kautz <rkautz@ndoil.org>
Sent: Tuesday, April 16, 2024 1:38 PM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Cc: Reva Kautz <rkautz@ndoil.org>
Subject: Re: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

Ron has changed his mind regarding the room set up. We no longer need a big rectangle with all attendees facing forward towards each other.

He is now feeling comfortable with the guests sitting at round tables throughout the space. He now requests a PA system for speakers included in a short agenda. Is there a way to have a head table near the fireplace for those speakers?

As of today, I have 31 planning on attending, which includes Gov Burgum.

Reva

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Tuesday, April 9, 2024 2:53 PM
To: Reva Kautz <rkautz@ndoil.org>
Subject: RE: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

Reva,

The past selection has consisted of:

White wine

Red wine

Fargo Brewing Co – Oktoberfest

Laughing Sun – Golden Ale

Black Leg – Copper Ale

Hope this gives Ron an idea He is free to choose other options as well.

Menu:

App – Walleye Cakes with Creole aioli and corn succotash

Main Dish – working on this with Chef– it will be a beef entrée – will keep you posted

Dessert – Peach cobber with vanilla bean ice cream and bourbon caramel.

If I can be of further assistance, please let me know.

With gratitude,

Connie

From: Reva Kautz <rkautz@ndoil.org>
Sent: Tuesday, April 9, 2024 11:22 AM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: Re: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

Yes, please forward that list of drinks and then we can keep you posted on when it is ordered and paid for.

Reva

From: Gulleson, Connie M. <cmgulleson@nd.gov>

Sent: Tuesday, April 9, 2024 9:57 AM
To: Reva Kautz <rkautz@ndoil.org>
Subject: RE: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

Reva,

I can get you a list of what has been used in the past to at least give you some ideas. If you want to call it in to the store of Ron's choice, place the order and pay for it, our team from the GR would be happy to go pick it up so they can prep it.

Hope that helps.

With gratitude,

Connie

From: Reva Kautz <rkautz@ndoil.org>
Sent: Tuesday, April 9, 2024 8:31 AM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: Re: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

Ron has been out of the office at meetings, but he has confirmed he is fine with taking care of the drinks.

Is he to select and bring the drinks to the Governor's residence, right?

We sent the invite to the VIP's so will share the RSVP count closer to the event.

In appreciation,

Reva

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Tuesday, April 9, 2024 8:26 AM
To: Reva Kautz <rkautz@ndoil.org>
Subject: RE: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

Morning Reva!

I am working on a room arrangement per Ron's request. It will depend on the final count but we will do what we can.

I should have a menu shortly to share.

With gratitude,

Connie

From: Reva Kautz <rkautz@ndoil.org>
Sent: Wednesday, March 20, 2024 9:58 AM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Cc: Reva Kautz <rkautz@ndoil.org>
Subject: Re: VIP Dinner at the Governor's Residence May 15, 2024 RE: ND Petroleum Council hosting Williston Basin Petroleum Conference

It was great to meet you on Monday at the Governor's Residence!

Since we have talked, Ron Ness shared that he would prefer that all the VIPs for this dinner be sitting facing each other to allow one conversation. Can 8-foot tables be placed into a rectangle with the chairs on the outside, instead of circle tables throughout the room? We won't need the podium.

Can you forward a map of the room to show if this is possible with the size of the room? I'm sure this depends on the count as well.

Thanks for your help,

Reva Kautz

Communications Director

North Dakota Petroleum Council

100 West Broadway, Suite 200

PO Box 1395

Bismarck, ND 58501

Office: 701.557.7744

rkautz@ndoil.org

www.ndoil.org

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MAY 14-16,2024 | BISMARCK, ND

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WILLISTON BASIN PETROLEUM CONFERENCE

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From: Miller, Tammy J.
To: Gulleson, Connie M.
Subject: RE: YOU"RE INVITED! - ND Petroleum Council March Board Events
Date: Friday, February 23, 2024 1:02:39 PM
Attachments: image001.png
image002.png
image003.png
image004.png
image005.png
image006.png
image007.png

Thanks. I will not attend the Thursday or Friday evening events in Grand Forks.

Tammy J. Miller
Lieutenant Governor

701.328.2200 • tjmiller@nd.gov • governor.nd.gov

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-
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-
-
-

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Friday, February 23, 2024 12:25 PM
To: Miller, Tammy J. <tjmiller@nd.gov>
Subject: FW: YOU'RE INVITED! - ND Petroleum Council March Board Events

Sorry, please see the attached agenda.

The plane will be going to GF that day ayways to pick up AG – but that would mean that you leave Bowman before the event is over.

From: Miller, Tammy J. <tjmiller@nd.gov>
Sent: Friday, February 23, 2024 12:19 PM
To: Gulleson, Connie M. <cmgulleson@nd.gov>
Subject: RE: YOU'RE INVITED! - ND Petroleum Council March Board Events

I don’t see any events on Thursday.

Tammy J. Miller

Lieutenant Governor

701.328.2200 • tjmiller@nd.gov • governor.nd.gov

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-
Sign up to receive updates from Governor Burgum
-
-
-

From: Gulleson, Connie M. <cmgulleson@nd.gov>
Sent: Friday, February 23, 2024 9:44 AM
To: Miller, Tammy J. <tjmiller@nd.gov>
Subject: FW: YOU'RE INVITED! - ND Petroleum Council March Board Events
Importance: High

You will be in Bowman for Thursday's activities. Just wanted to make sure you were good if I rsvp'd no for Thursday but yes to Friday.

Thanks!
Connie

From: Brady Pelton <bpelton@ndoil.org>
Sent: Friday, February 23, 2024 9:38 AM
To: Brady Pelton <bpelton@ndoil.org>
Cc: Micaela Rud <mrud@ndoil.org>
Subject: RE: YOU'RE INVITED! - ND Petroleum Council March Board Events
Importance: High

Good morning, and a happy Friday to you!

As we make final preparations for next week's activities, I wanted to be sure to reach out to those I have not heard from yet regarding the North Dakota Petroleum Council's invitation to join its Board of Directors and other honored guests for the Friday, March 1 hockey game at the University of North Dakota. Puck drop is scheduled for 7:07 at the world-class Ralph Engelstad Arena, and we would be honored to have you join us as the Fighting Hawks take on Western Michigan.

If you are able to join us, please RSVP here: NDPC Social & Hockey Night
So we can have an adequate number of tickets, **please RSVP by end of business today if at all possible**.

Thank you for all you do for our state, and we look forward to visiting with you next week in Grand Forks!

Best regards,
Brady

Brady Pelton
Vice President & General Counsel

North Dakota Petroleum Council

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From: Brady Pelton
Sent: Monday, February 12, 2024 5:15 PM
To: Brady Pelton <bpelton@ndoil.org>
Cc: Micaela Rud <mrud@ndoil.org>
Subject: YOU'RE INVITED! - ND Petroleum Council March Board Events
Importance: High

Good afternoon, North Dakota leaders:

The North Dakota Petroleum Council Board of Directors and guests are eagerly awaiting our February 29-March 1 visit to Grand Forks and the University of North Dakota!

In advance of our two-day visit, we wanted to share the invitation below from the Energy & Environmental Research Center (EERC):

> You are cordially invited to a luncheon at the University of North Dakota (UND) Energy & Environmental Research Center (EERC) on Friday, March 1, 2024, at noon. Attendees include state and local leaders and North Dakota Petroleum Council members.
>
> Following the luncheon, you have an opportunity to tour the EERC or the College of Engineering & Mines (CEM). You can join the EERC for a journey

through the EERC's expanding array of projects, deeply meaningful for our state, and the entire region.

- Option 1: At the EERC, the tour will include, but not be limited to, research on Bakken, salt caverns, rare-earth elements, CO_2 capture and storage, development of new materials, and the latest update to our expanding hydrogen program. During the tour, you will hear from our professional research staff who bring a wealth of expertise to these impactful areas. The EERC team is looking forward to answering any questions you may have and the opportunity to connect with leadership from North Dakota and our entire region.
- Option 2: Dean Brian Tande will lead a tour of the College of Engineering & Mines National Security Corridor and the Collaborative Energy Center. CEM research has grown by more than 40% in the past several years, with over $9M in areas such as energy, rare-earth elements, UAS, and national security.

Please RSVP by February 15, 2024, for both the luncheon and the tour at this link: use this link.

Capping off the events on Friday, NDPC will host a social at the CanadInn's Playmakers Lounge from 4:30 to 6:00 p.m. and then host guests at the Ralph as UND takes on Western Michigan in some good old North Dakota hockey. Hockey tickets are sponsored by our great friends at AE2S, Construction Engineers, and the UND Alumni Association & Foundation. We have a hockey ticket for you. However, if you have access to other tickets, please use those and find us on the suite level (Suites 201 and 204; Alumni Association suite is 225).

In order to best prepare for meals and other logistics, we ask that you RSVP by February 15th at each of the links below.

Friday, March 1 - EERC Lunch & Tour Invite
Friday, March 1 - NDPC Social & Hockey Night

Thank you all for your continued support and please contact me with any questions. We look forward to seeing each of you.

Best regards,
Brady

Brady Pelton
Vice President & General Counsel

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Bismarck, ND 58501

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NORTH DAKOTA
PETROLEUM
COUNCIL

www.NDOil.org | www.NDOilFoundation.org

MAY 14-16, 2024 | BISMARCK, ND

BAKKEN NOW

WILLISTON BASIN PETROLEUM CONFERENCE

SAVE THE DATE

WWW.WBPCND.COM

From: Brady Pelton
To: NDPC
Subject: Special Invitation to 2024 Williston Basin Petroleum Conference: May 14-16, 2024 in Bismarck, North Dakota
Date: Monday, April 1, 2024 8:45:51 AM
Attachments: image.png
image.png
image002.png
image003.png
image004.png
image001.wmz
image006.png
Importance: High

Good morning!

On behalf of the North Dakota Petroleum Council, it is my distinct privilege to invite you to the **31st Annual Williston Basin Petroleum Conference** taking place **May 14-16, 2024** at the **Bismarck Event Center** in Bismarck, North Dakota. Below are links to additional information on this premier oil and gas industry event, including the Conference agenda, list of presenters, exhibitor information, and more!

As our special guest to the event, we are pleased to offer you registration to this exciting event for a registration fee of $50! To register, simply click on the green "REGISTER" link below and complete the registration process under the "Government" registration type. As you enter the Registration Information page to enter your information, be sure to select "Yes" when asked if you have a promocode and enter **24Gov** in the promocode box at the bottom to take advantage of the low-fee registration option.

We look forward to seeing you at this year's Williston Basin Petroleum Conference! As always, please do not hesitate to contact me with any questions.

BAKKEN NOW

SPECIAL GUEST LOW-FEE REGISTRATION

Register under the "Government" registration type and enter code 24Gov in the "promocode" box of the Registration Information page to take advantage of the $50 registration fee option.

WILLISTON BASIN PETROLEUM CONFERENCE

MAY 14-16, 2024

Bismarck Event Center, Bismarck, ND

The Best and the Brightest to Gather at the 2024 Williston Basin Petroleum Conference

The nation's leading oil and natural gas experts will gather at the 31st annual Williston Basin Petroleum Conference (WBPC) to discuss industry innovations and energy challenges and opportunities on May 14-16, 2024, at the Bismarck Event Center in Bismarck, ND.

A STAR-STUDDED AGENDA

The three-day conference will host over seventy speakers, including Kathleen Sgamma, Western Energy Alliance; Neel Kashkari, Minneapolis Federal Reserve Bank; Douglas Sandridge, Fulcrum Energy Capital Funds; Chris Wright, Liberty Energy; and Nick Olds, ConocoPhillips.


NEEL KASHKARI


DOUG SANDRIDGE


CHRIS WRIGHT


NICK OLDS

There will be multi-session workshops featuring technical, operational, and workforce solutions. Discussions among industry experts will include capitalizing on sustainability and how to navigate new regulations. Review the full, amazing agenda on the conference website: www.WBPCND.com

LEARN WHAT'S NEW IN THE BAKKEN

Continuous innovation and improved completion practices have helped our industry lessen our impact on the environment while decreasing drilling days and costs and increasing oil recovery per well. Our industry leads the world in the design and implementation of clean and efficient oil and natural gas exploration, development, and production technologies.

SOLD OUT TRADE SHOW

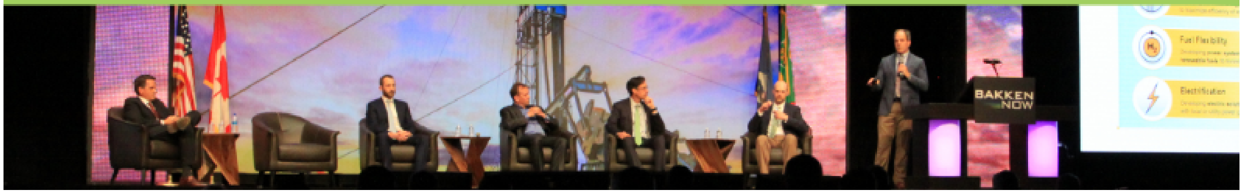
With over 300 indoor and outdoor exhibits and booths, you are bound to see exciting new technology and meet people who can help you take your career and business to the next level. The trade show's largest exhibitors include: Chord Energy, Marathon Oil, Continental Resources, Halliburton, and ConocoPhillips.

FIVE BILLION BAKKEN BARRELS

DON'T MISS THIS PARTY

Tuesday evening, May 14th, there will be the 5 Billion Bakken Barrell party celebrating the milestone of having produced five billion barrels of oil in the Bakken with a hosted bar and BBQ sponsored by Halliburton. Don't forget to grab your free, limited edition commemorative gift!

REGISTER TODAY! www.wbpcnd.com



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MAY 14-16,2024 | BISMARCK, ND
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